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E21B 7/20 33/14 43/10

(52) UK CL (Edition S)
E1F FAC FAC9 FLA

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(58) Field of Search
UK CL (Edition S) B3J, E1F FJT FLA
INT CL^7 B21D, E21B
Online: WPI, EPODOC, JAPIO

(54) Abstract Title
An expansion mandrel having a lubricating and self-cleaning system

(57) An expansion mandrel 5100 includes a lubrication system for lubricating the trailing edge portion of the interface between the mandrel and a tubular member. During radial expansion of the tubular member, lubricating fluids are transmitted from the area in front of the mandrel into circumferential grooves 5115a and b via internal flow passages 5120a and b. Other configurations of grooves and flow passages on the mandrel are disclosed (figs 33-39).

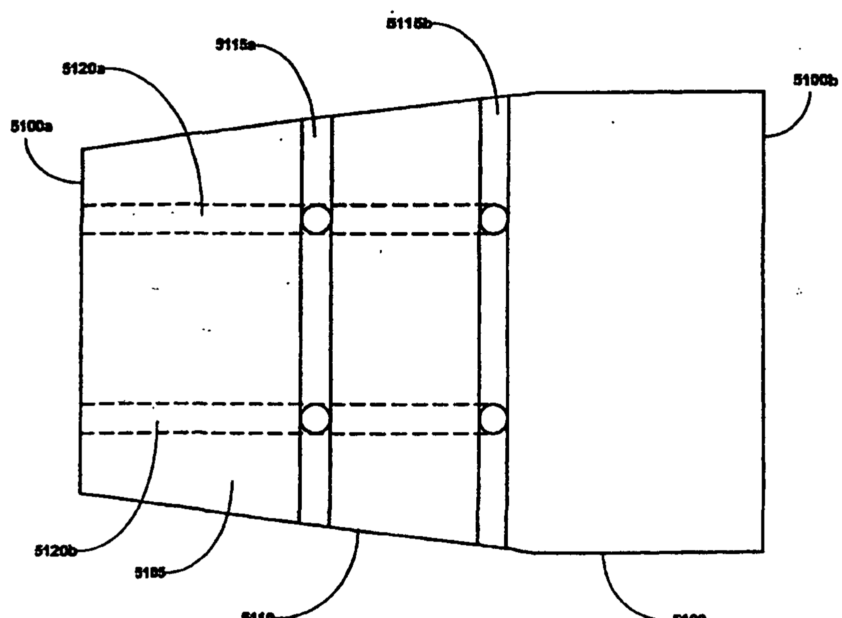

FIGURE 32

GB 2 356 651 A

This is a reprint to rectify errors introduced in the course of reproduction-Original Claims attached-18.06.2001

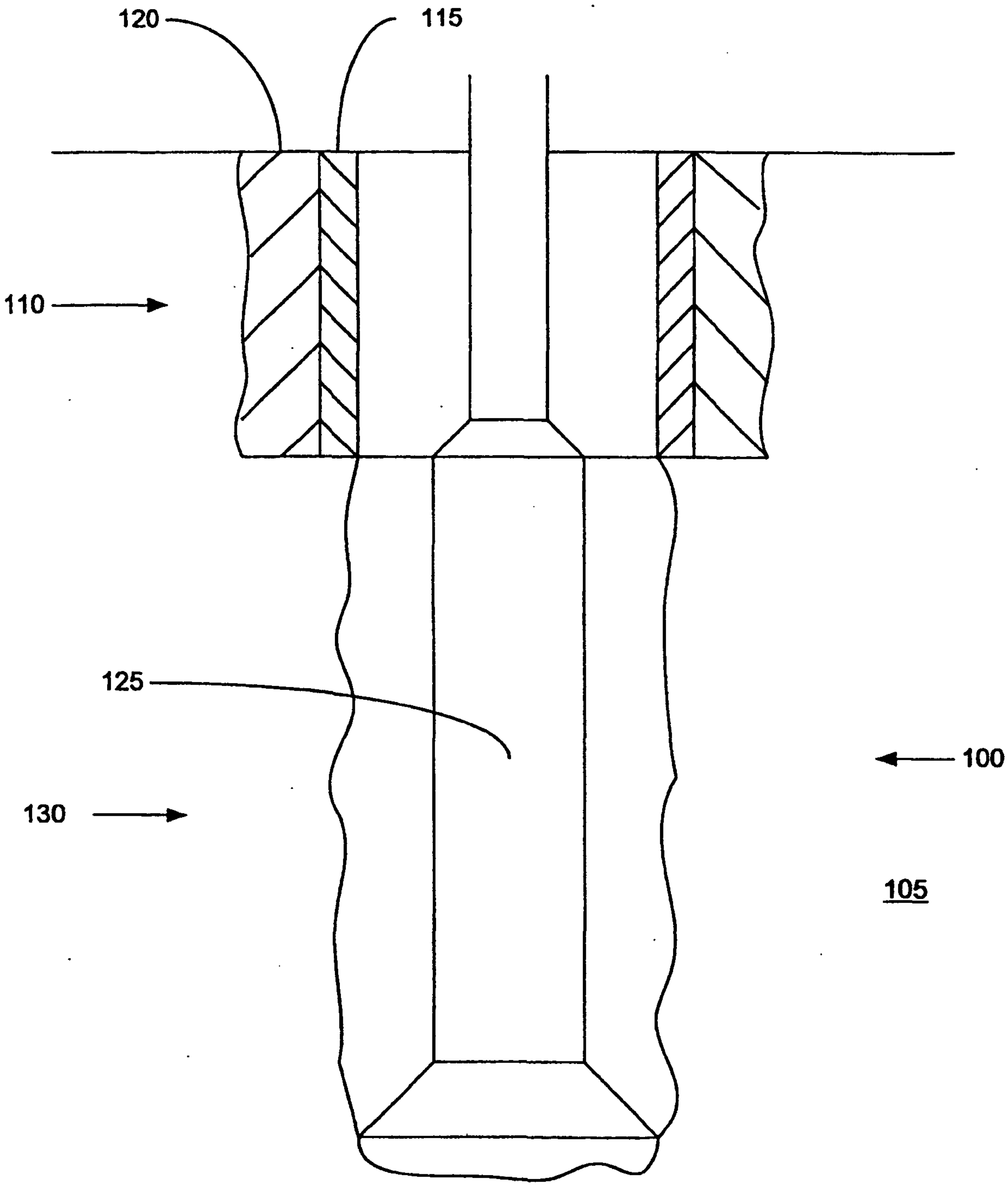

FIGURE 1

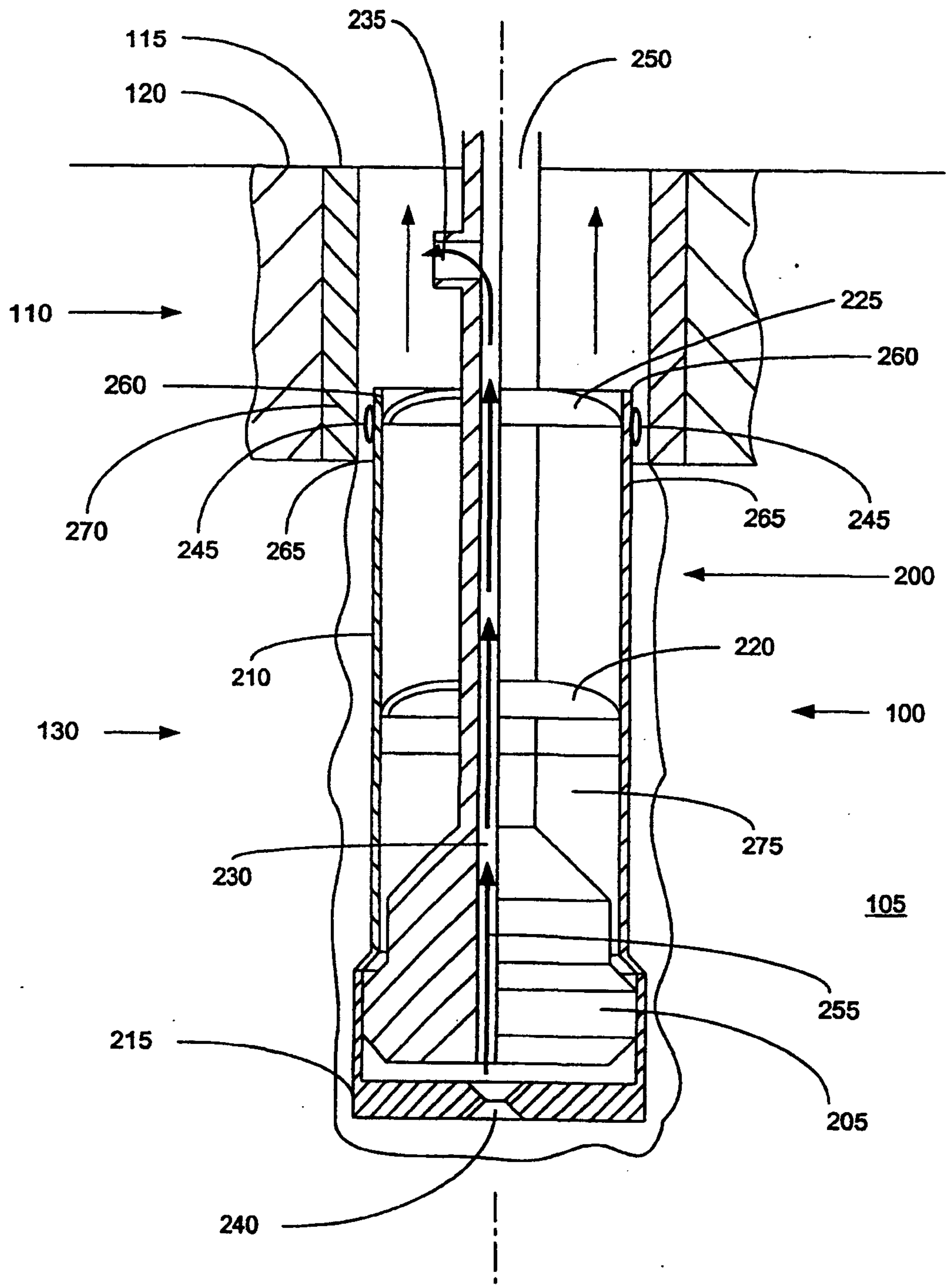
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FIGURE 2

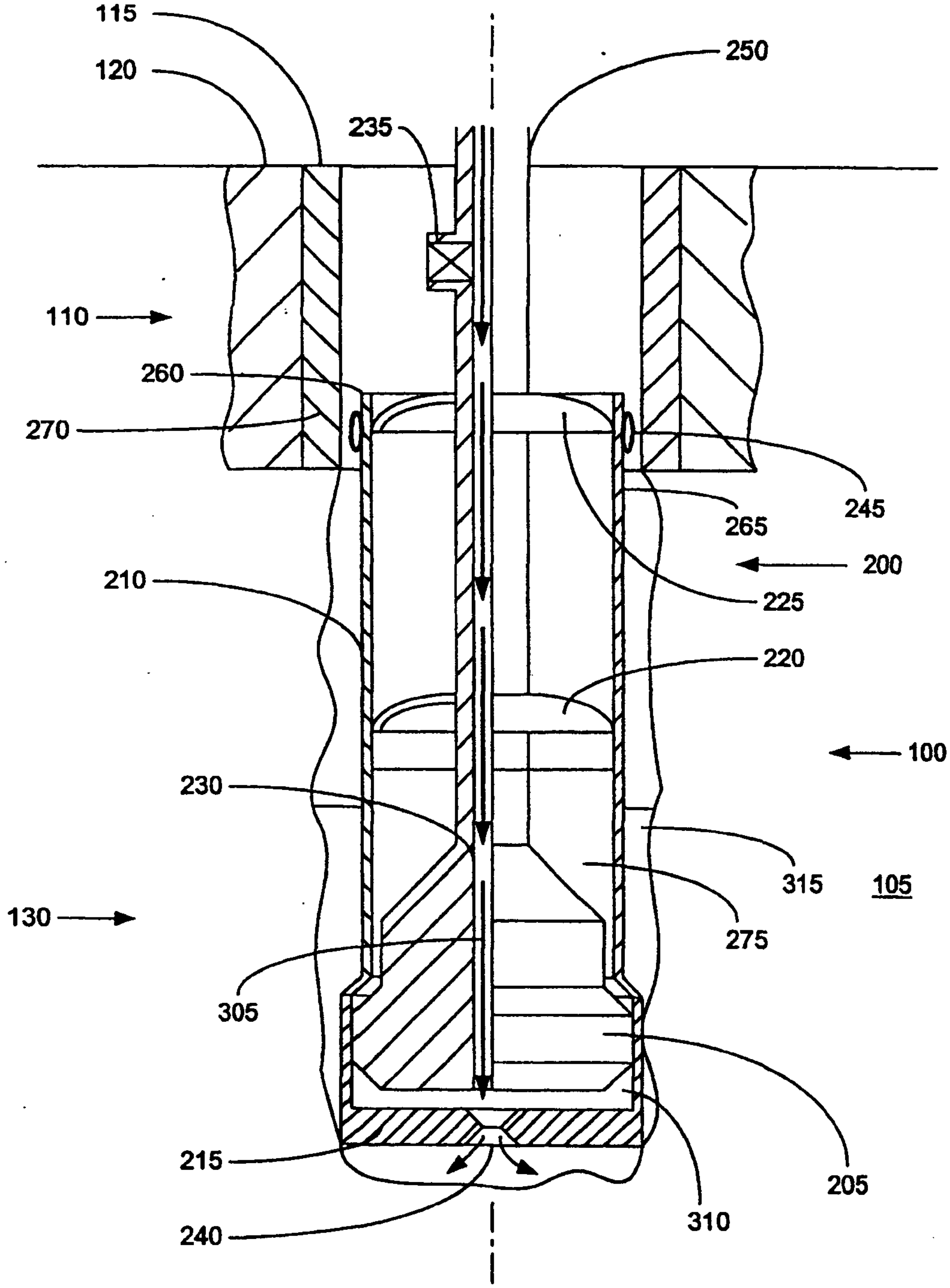
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FIGURE 3

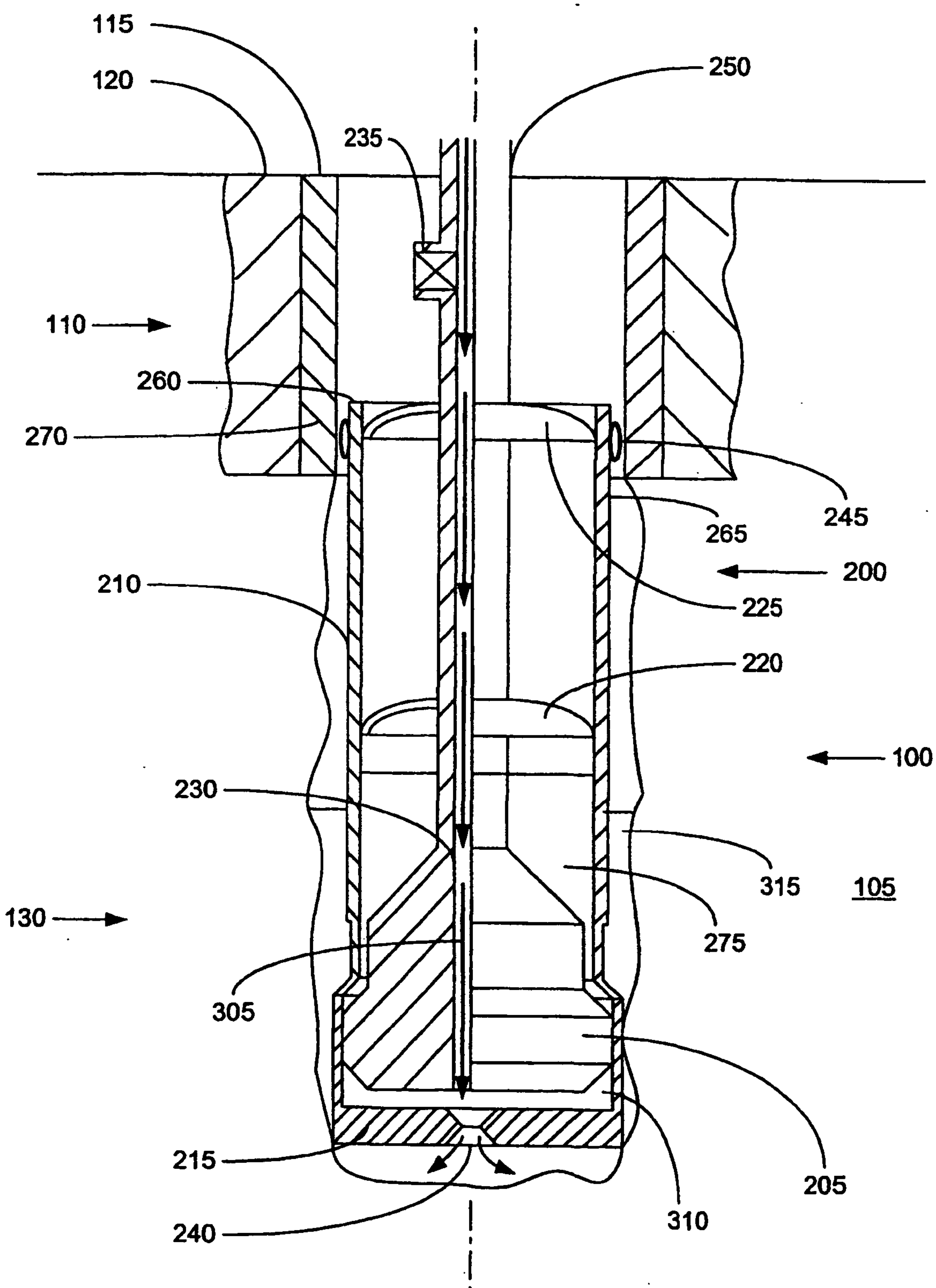
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FIGURE 3a

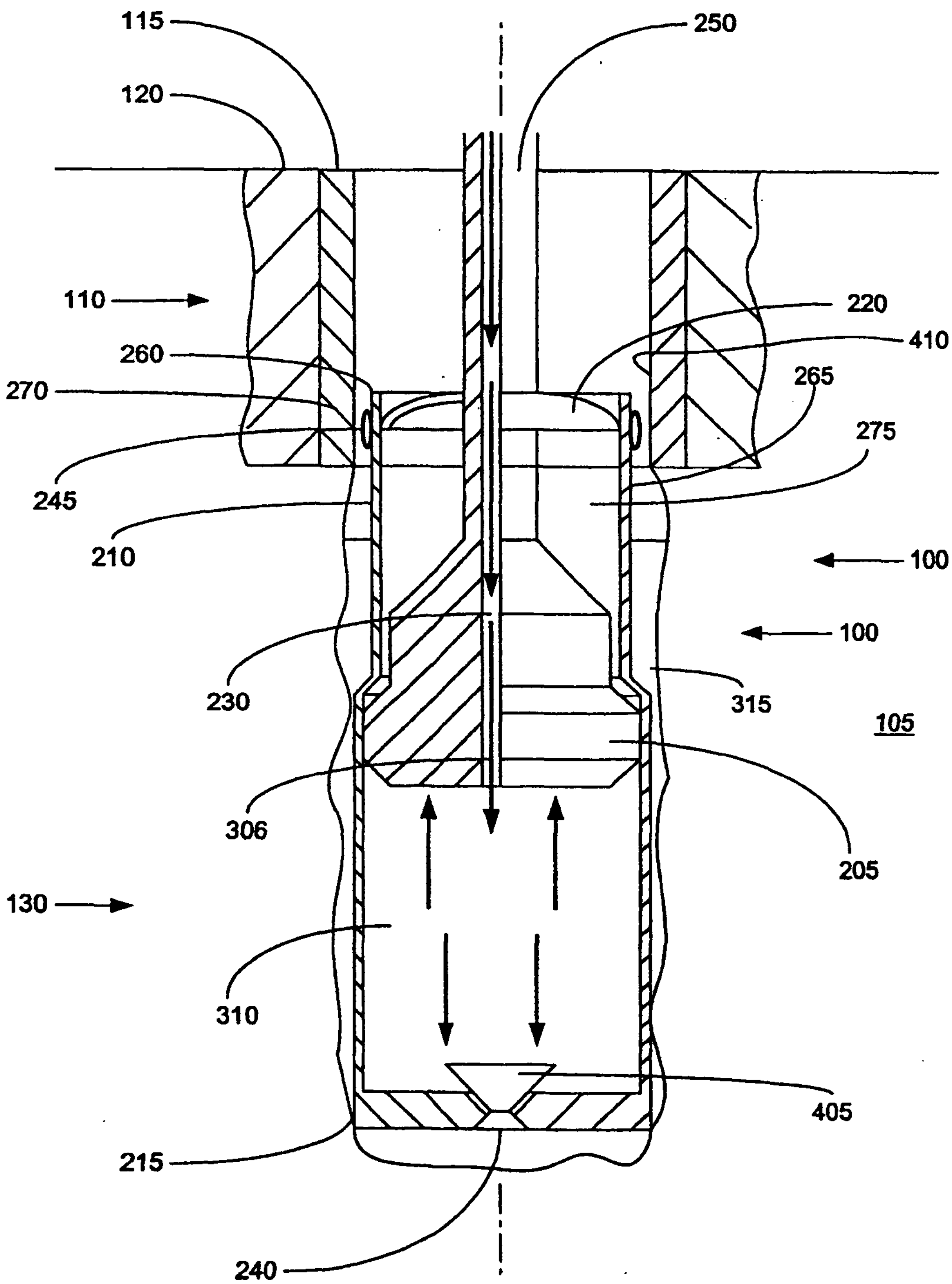
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FIGURE 4

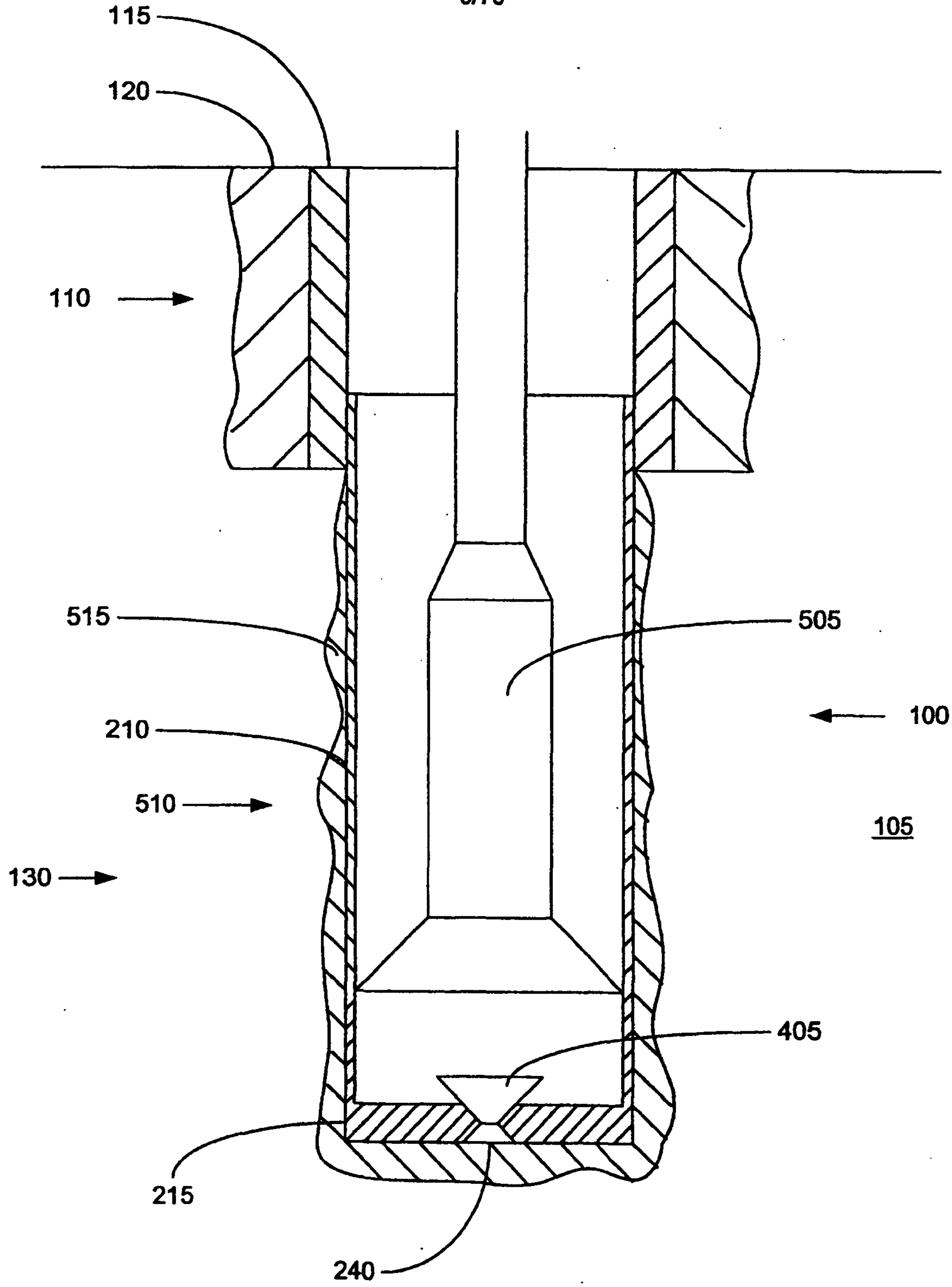


FIGURE 5

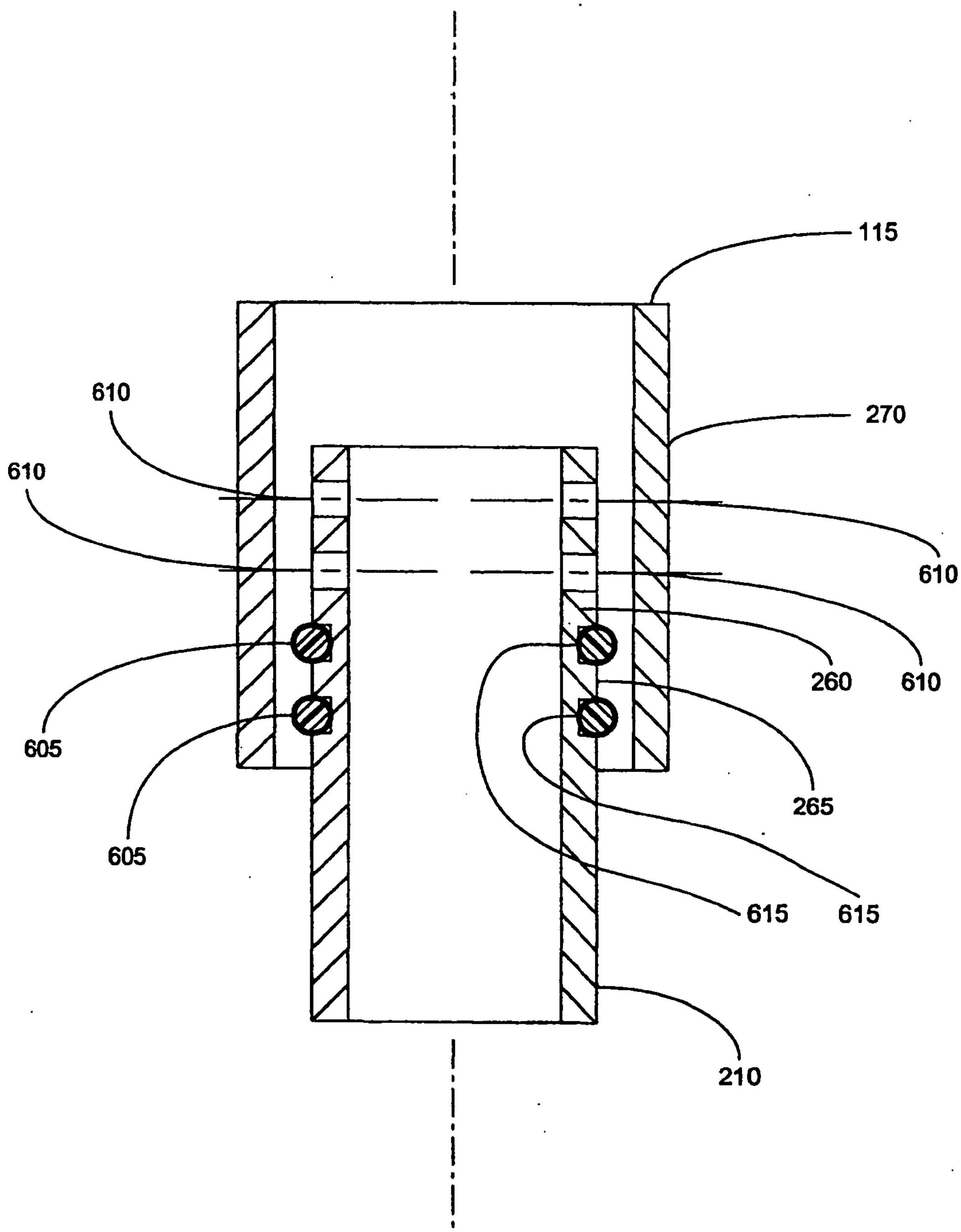
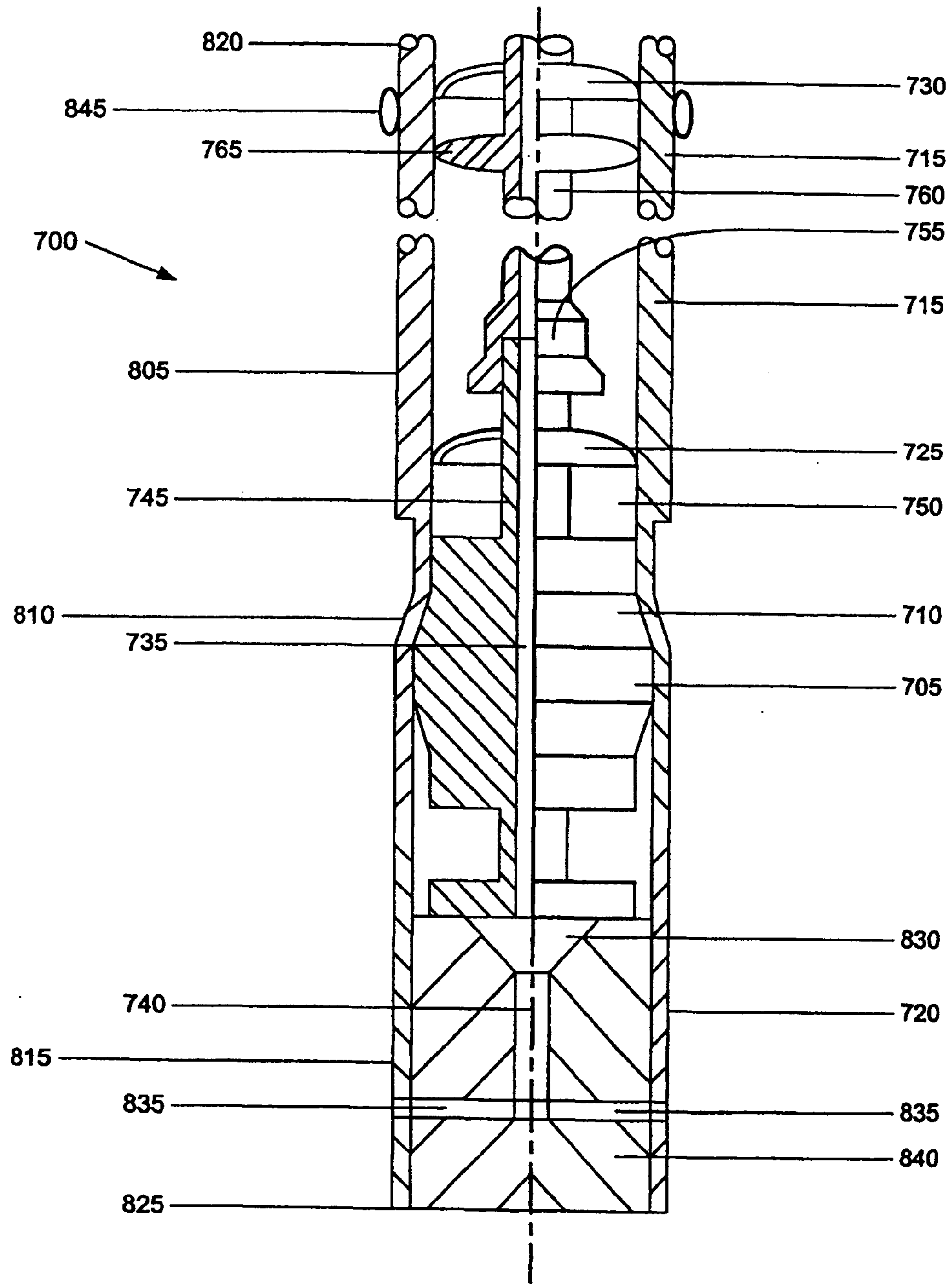


FIGURE 6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720
835
840

FIGURE 7

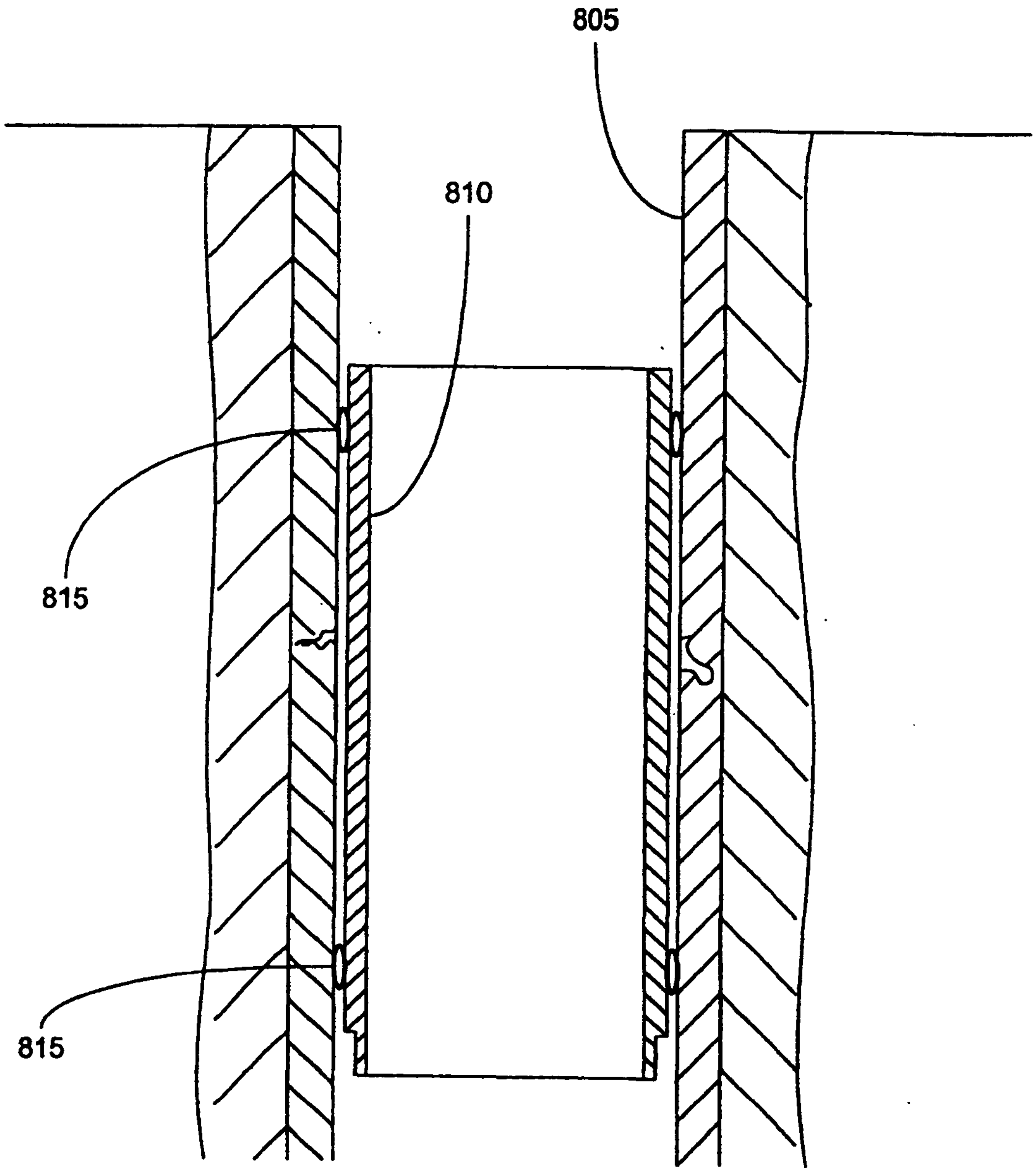

FIGURE 8

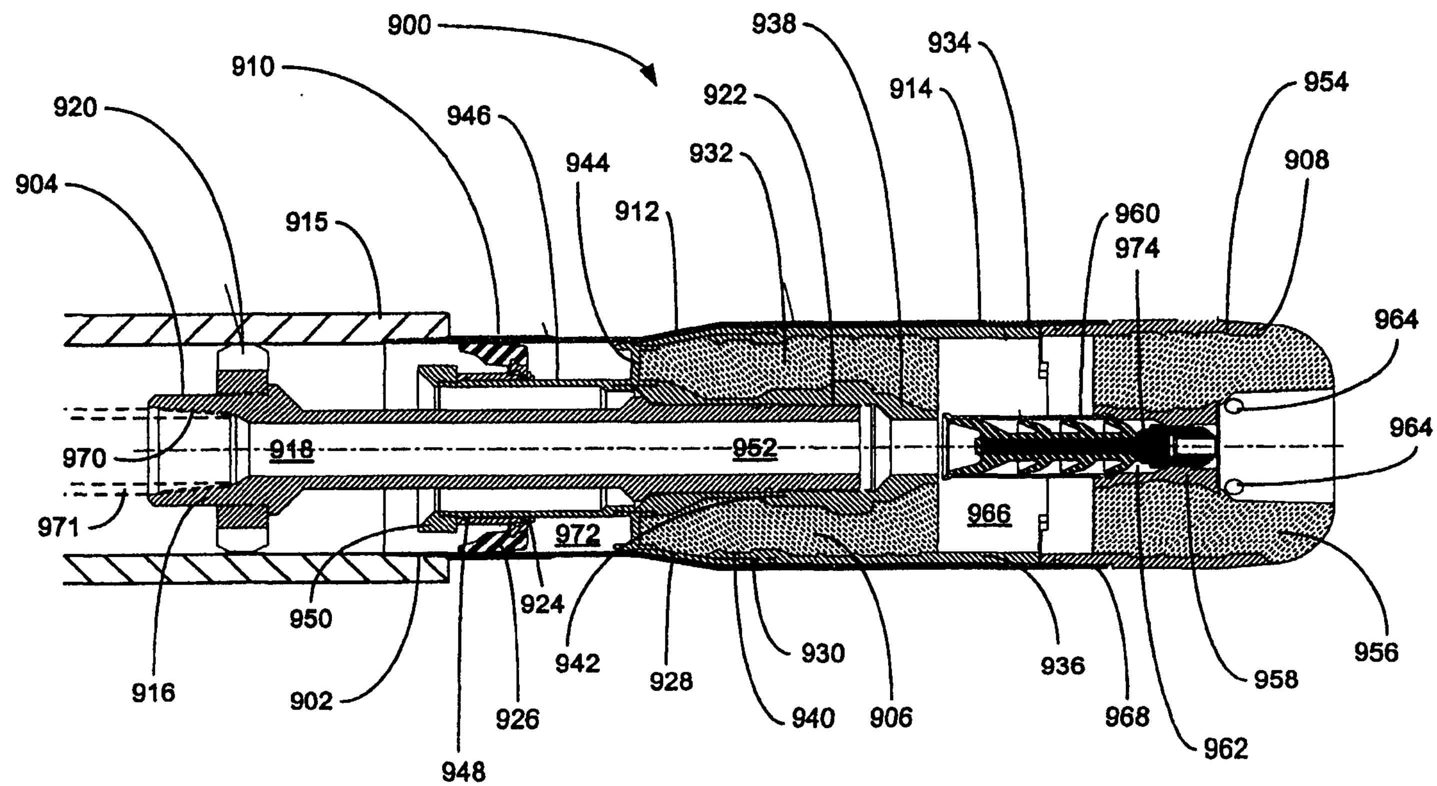
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FIGURE 9

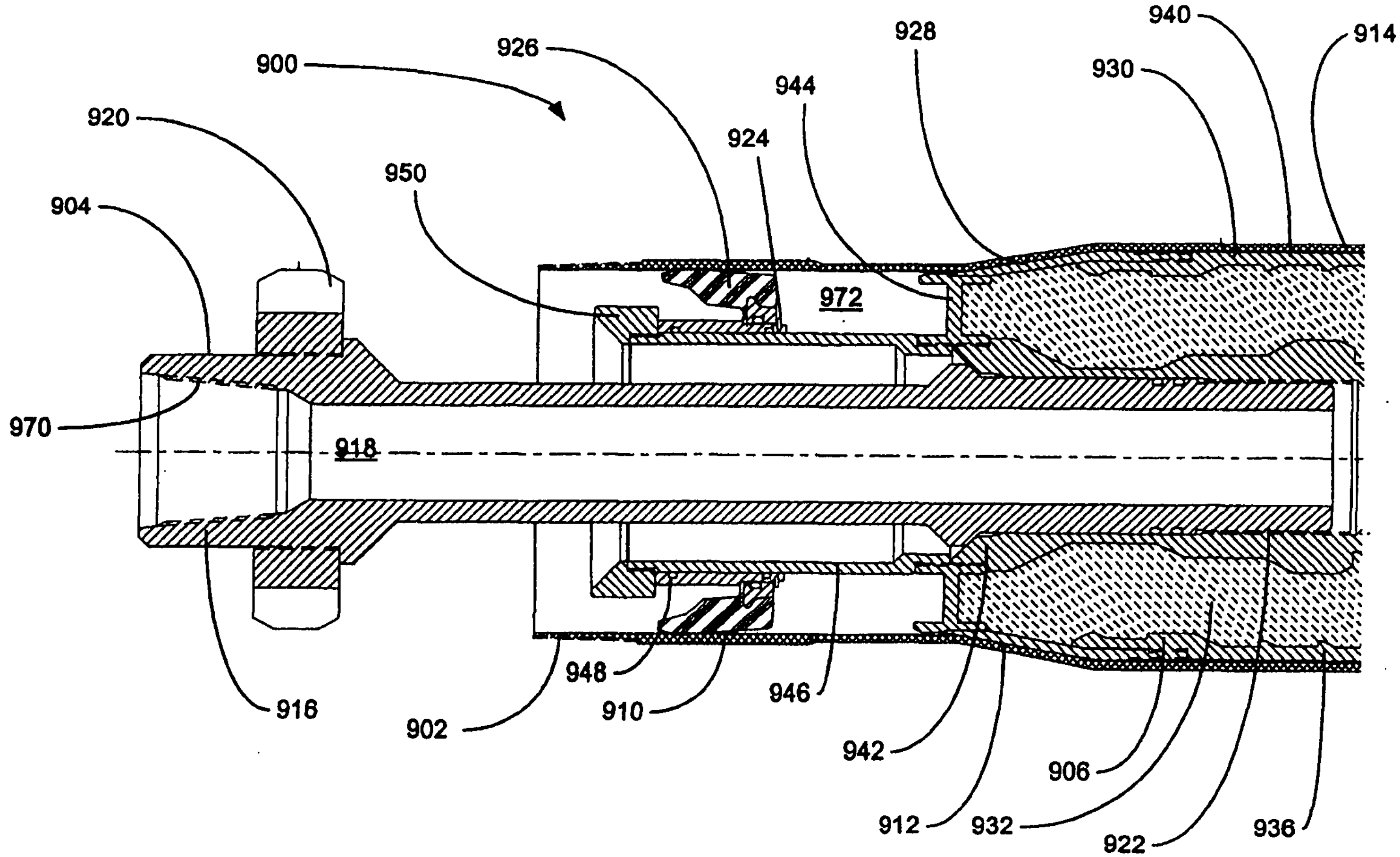
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FIGURE 9a

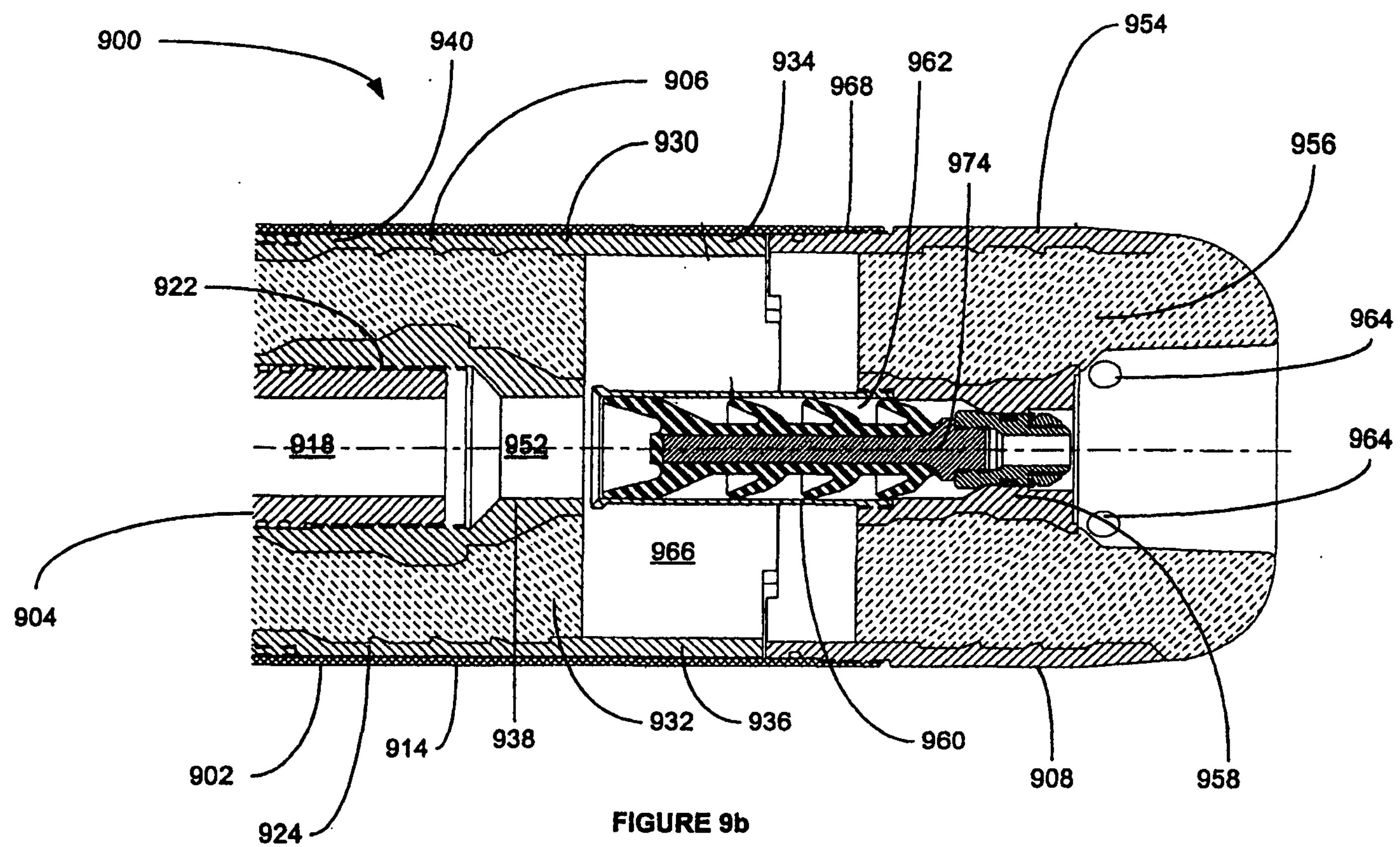
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FIGURE 9b

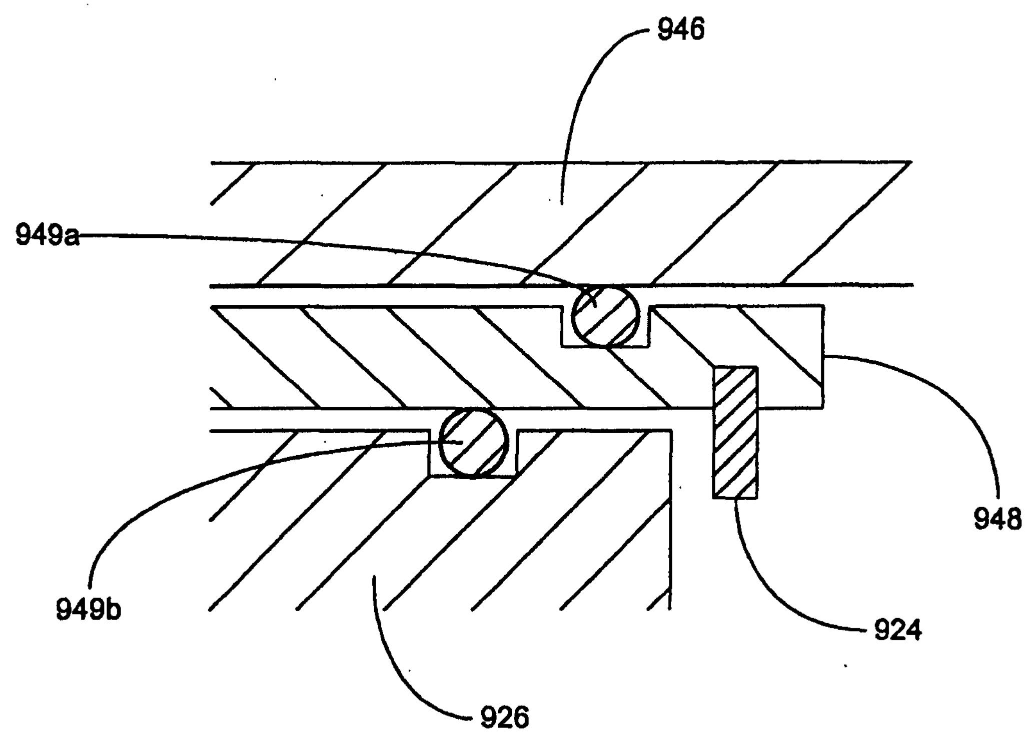

FIGURE 9C

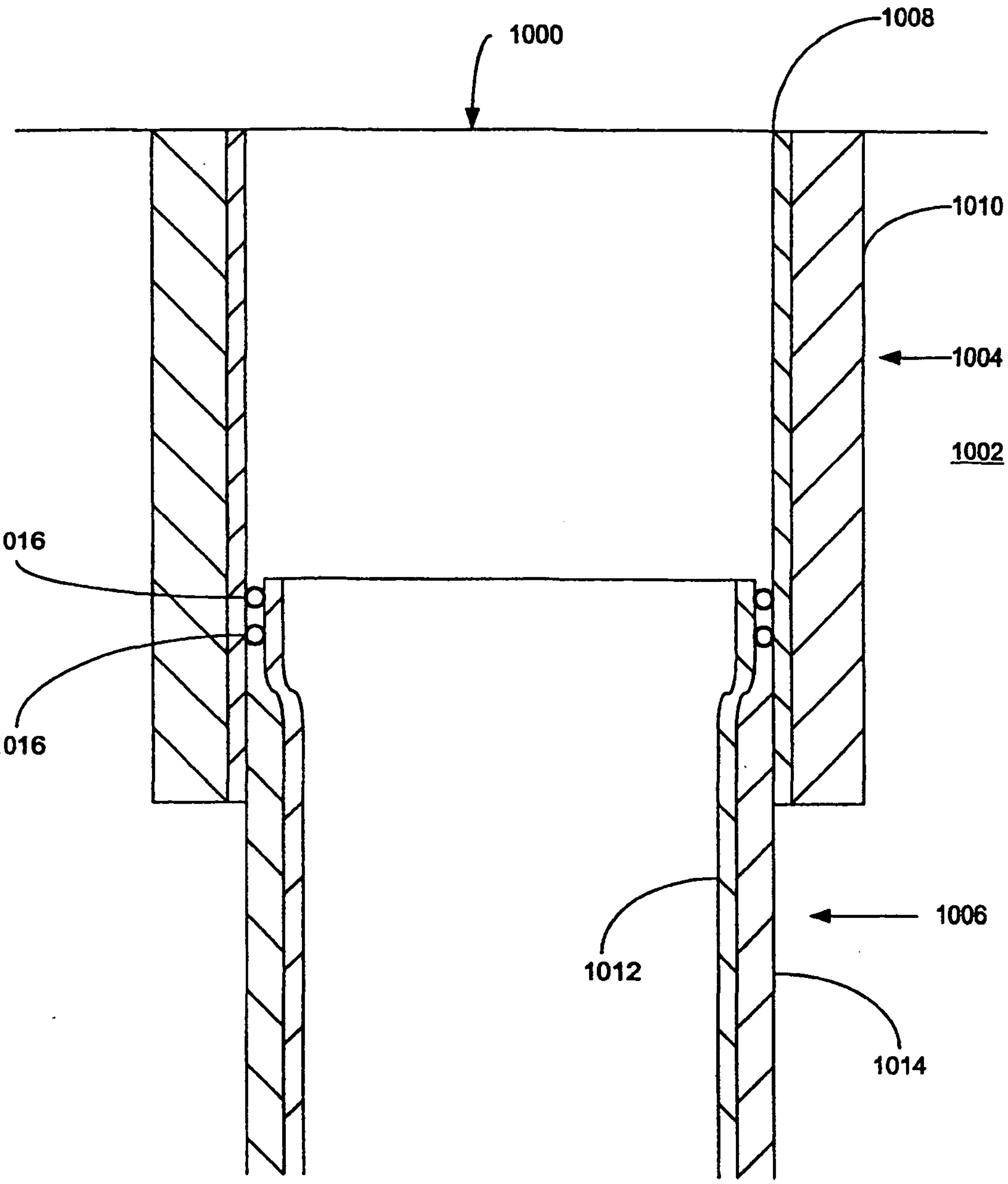

FIGURE 10a

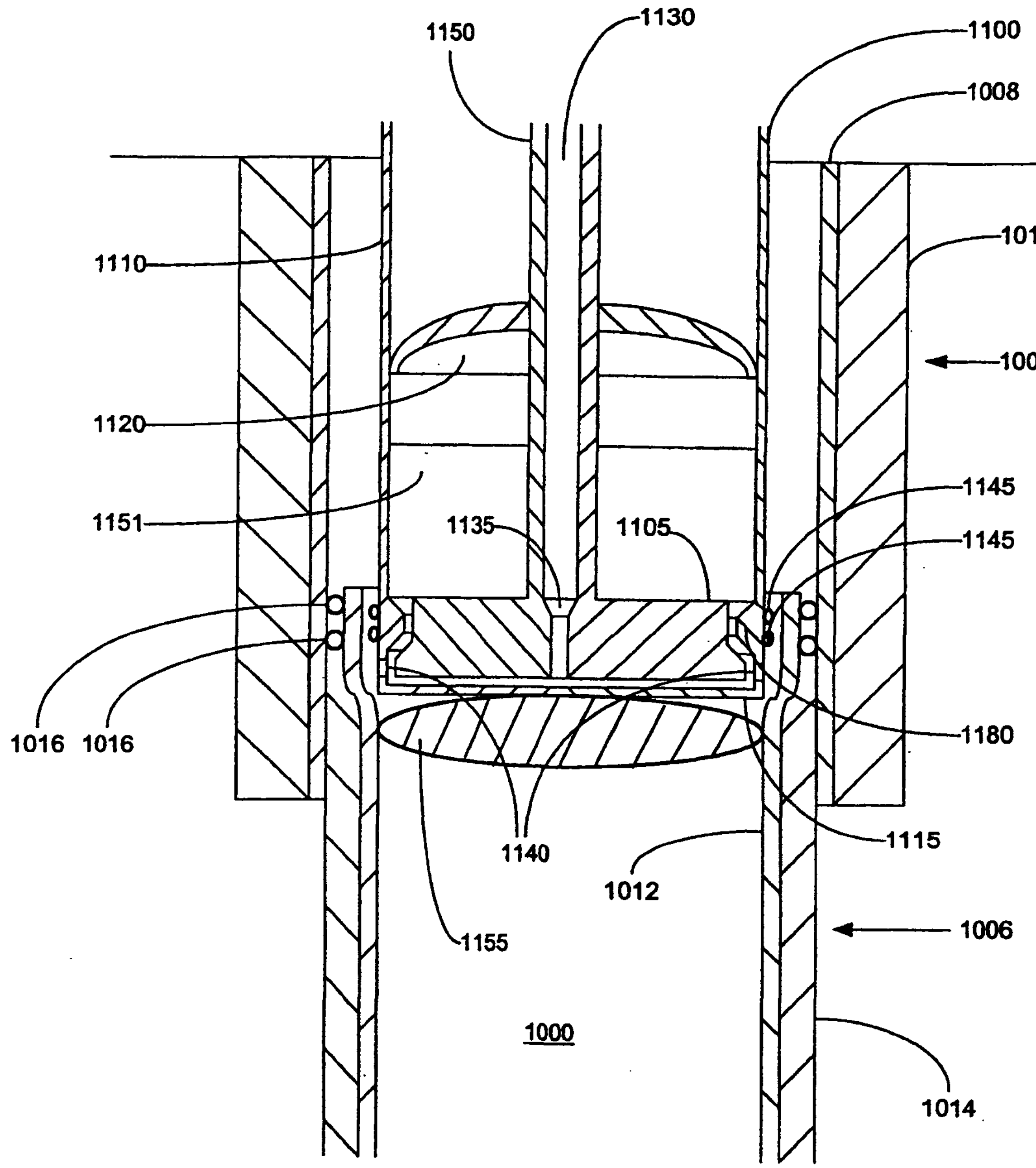
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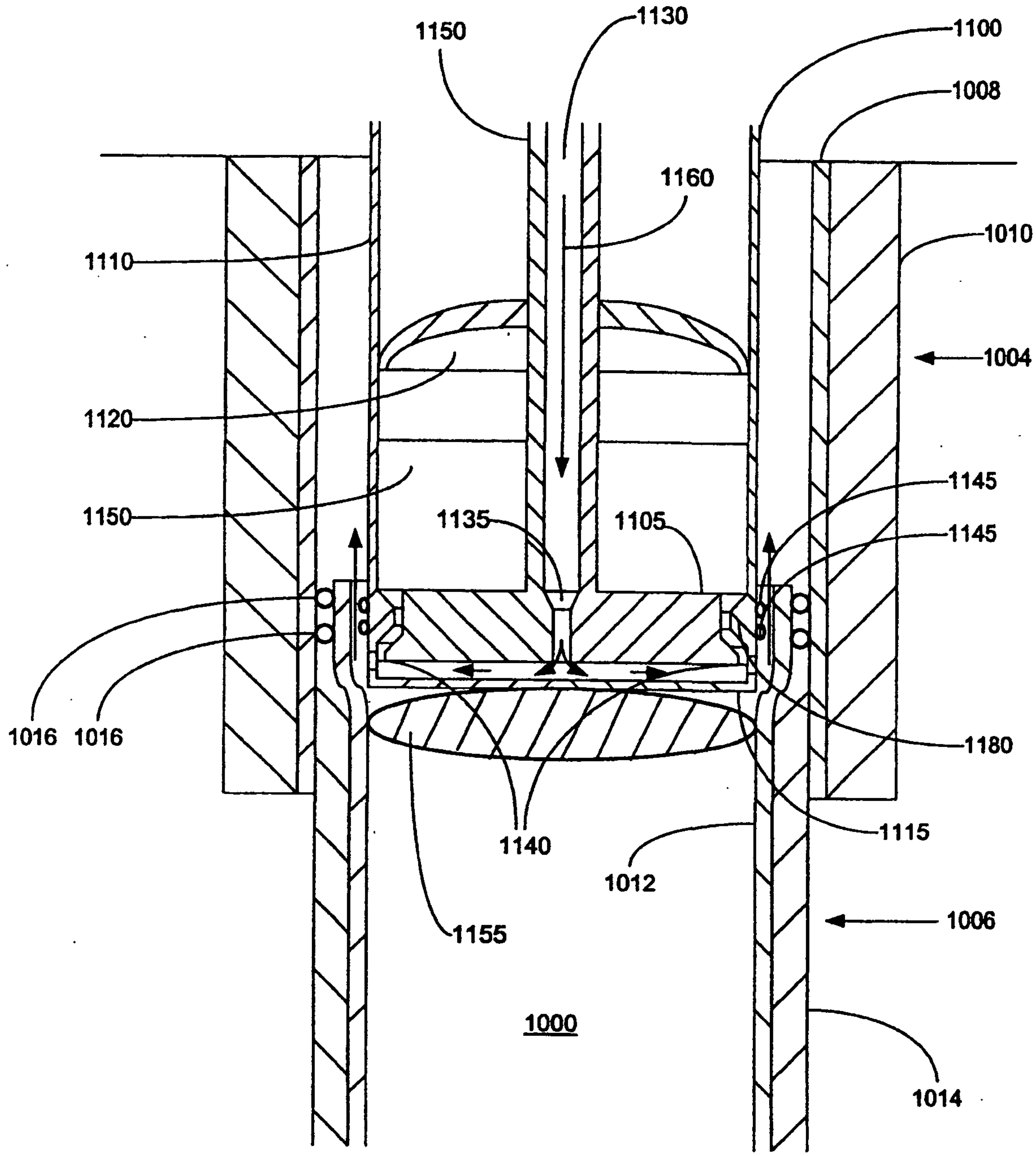
FIGURE 10b



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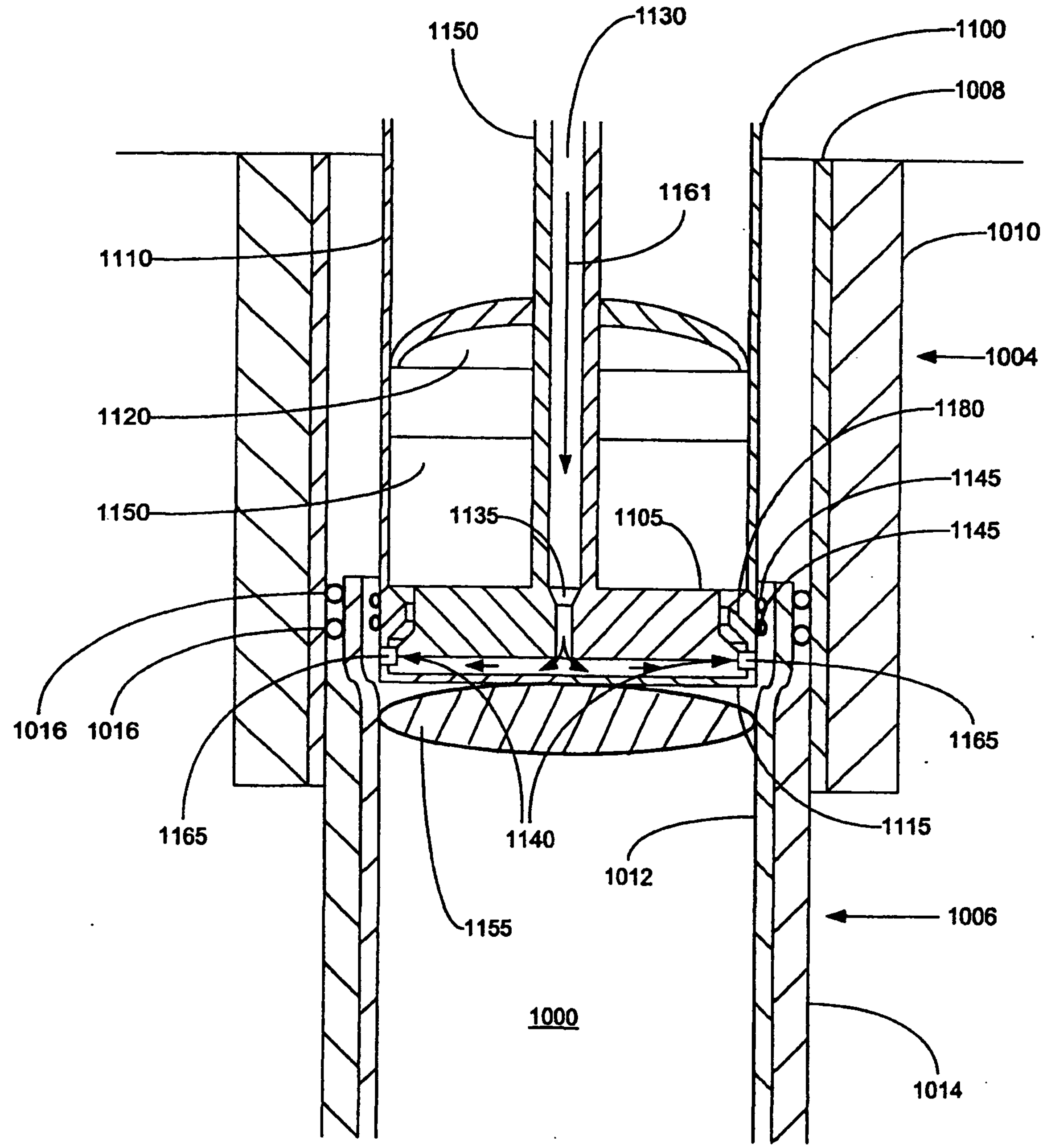
1000
1014

FIGURE 10c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1006
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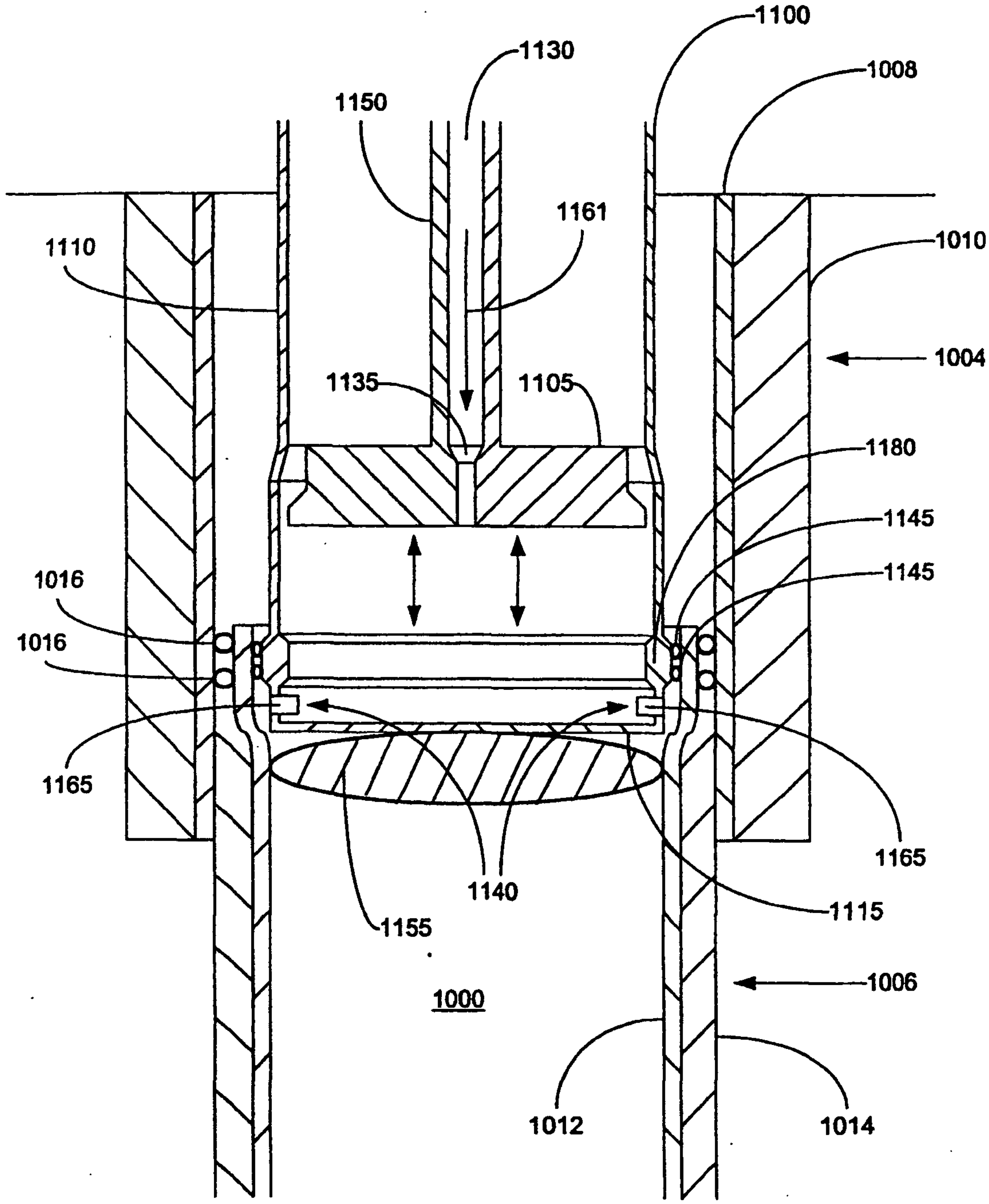
1014

FIGURE 10d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1012
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FIGURE 10e

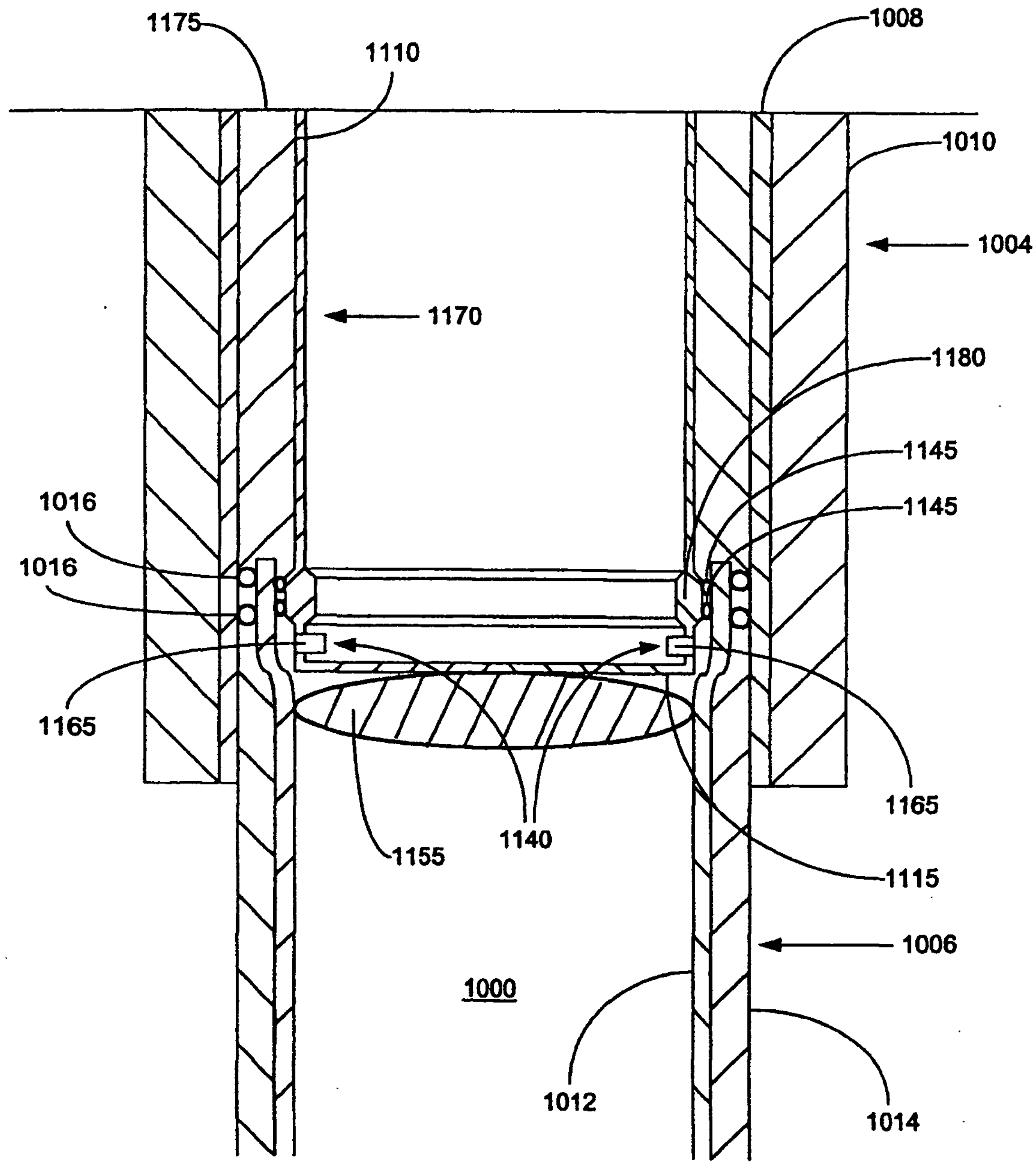
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FIGURE 10f

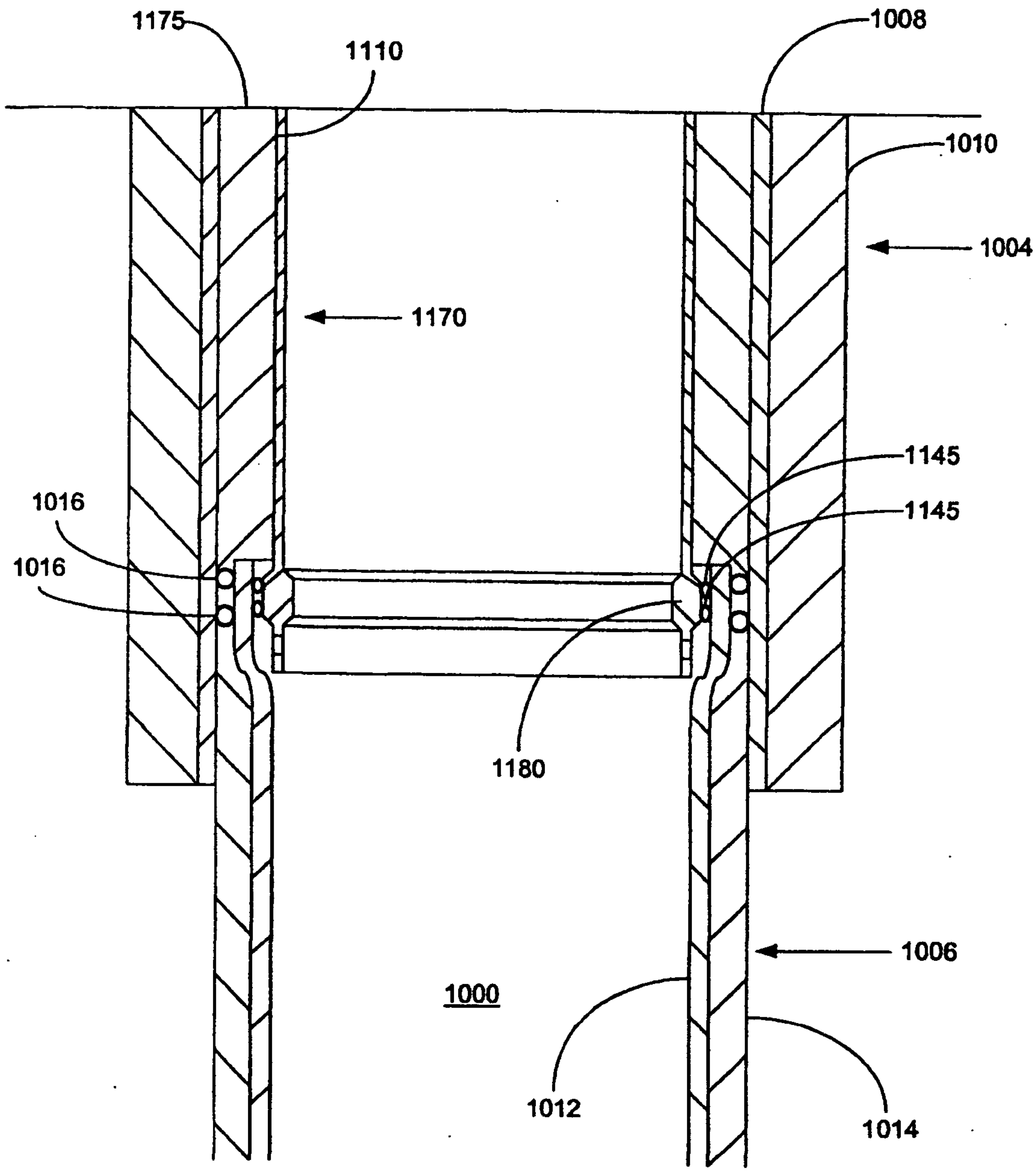
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FIGURE 10g

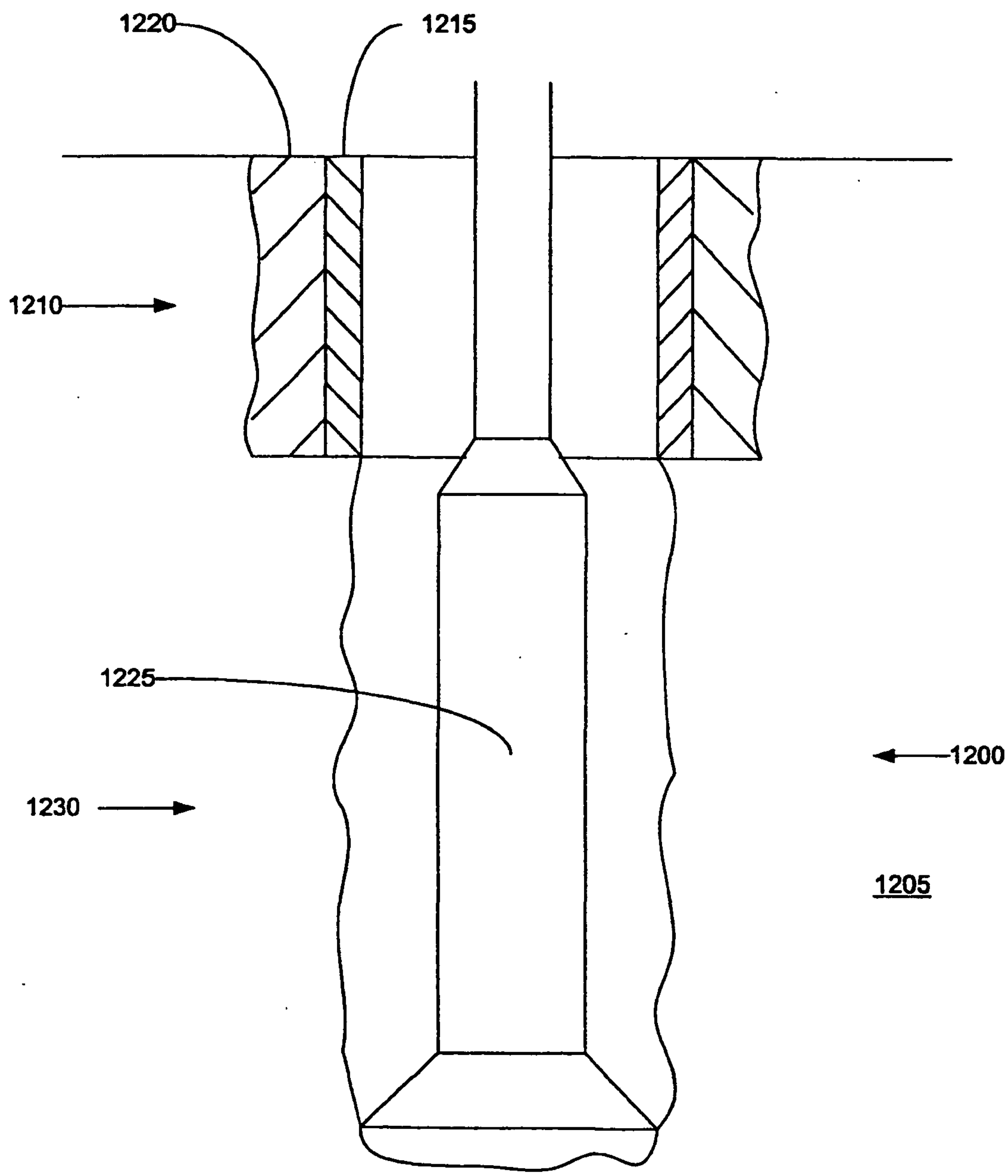

FIGURE 11a

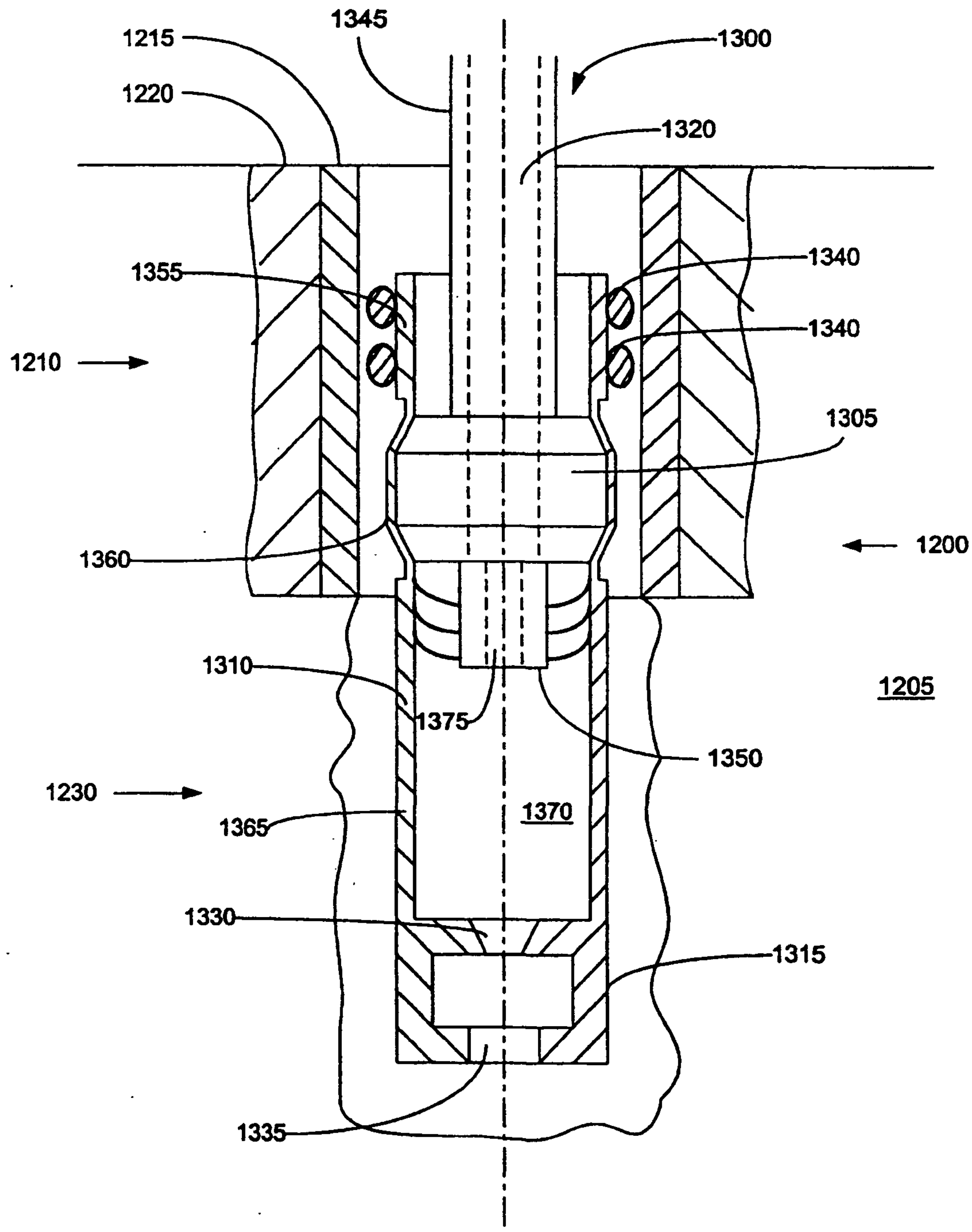
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FIGURE 11b

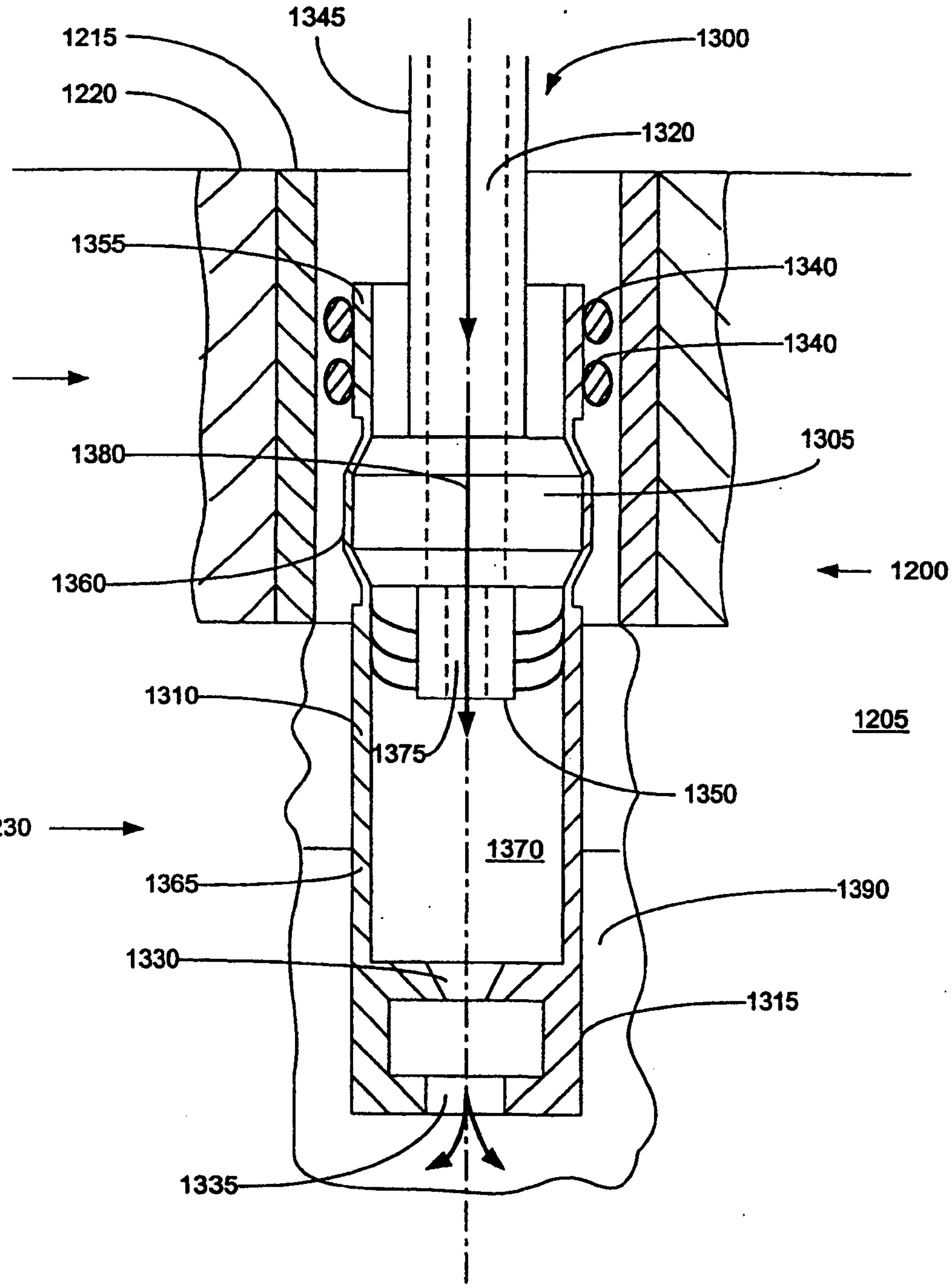
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FIGURE 11c

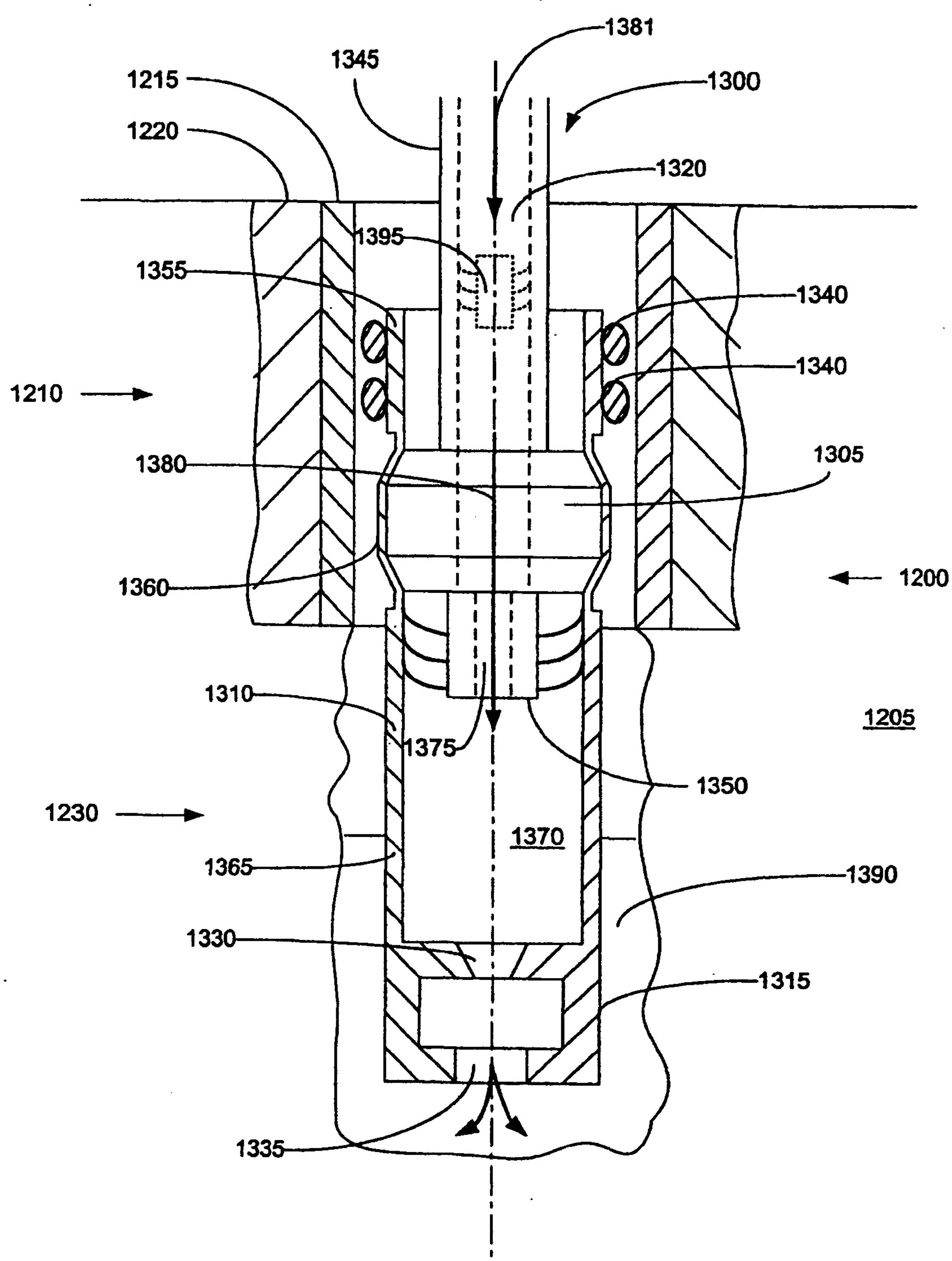
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FIGURE 11d

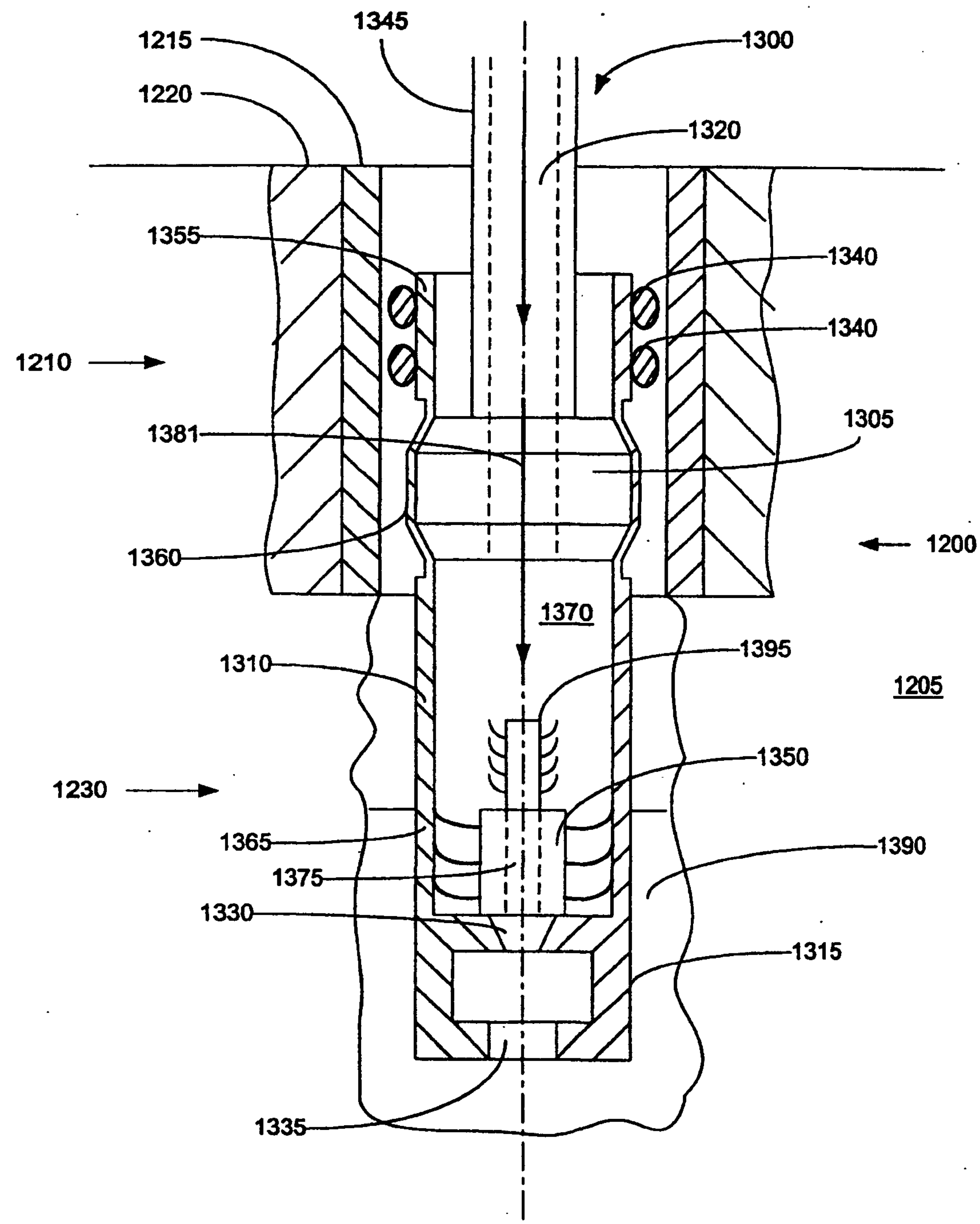
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FIGURE 11e

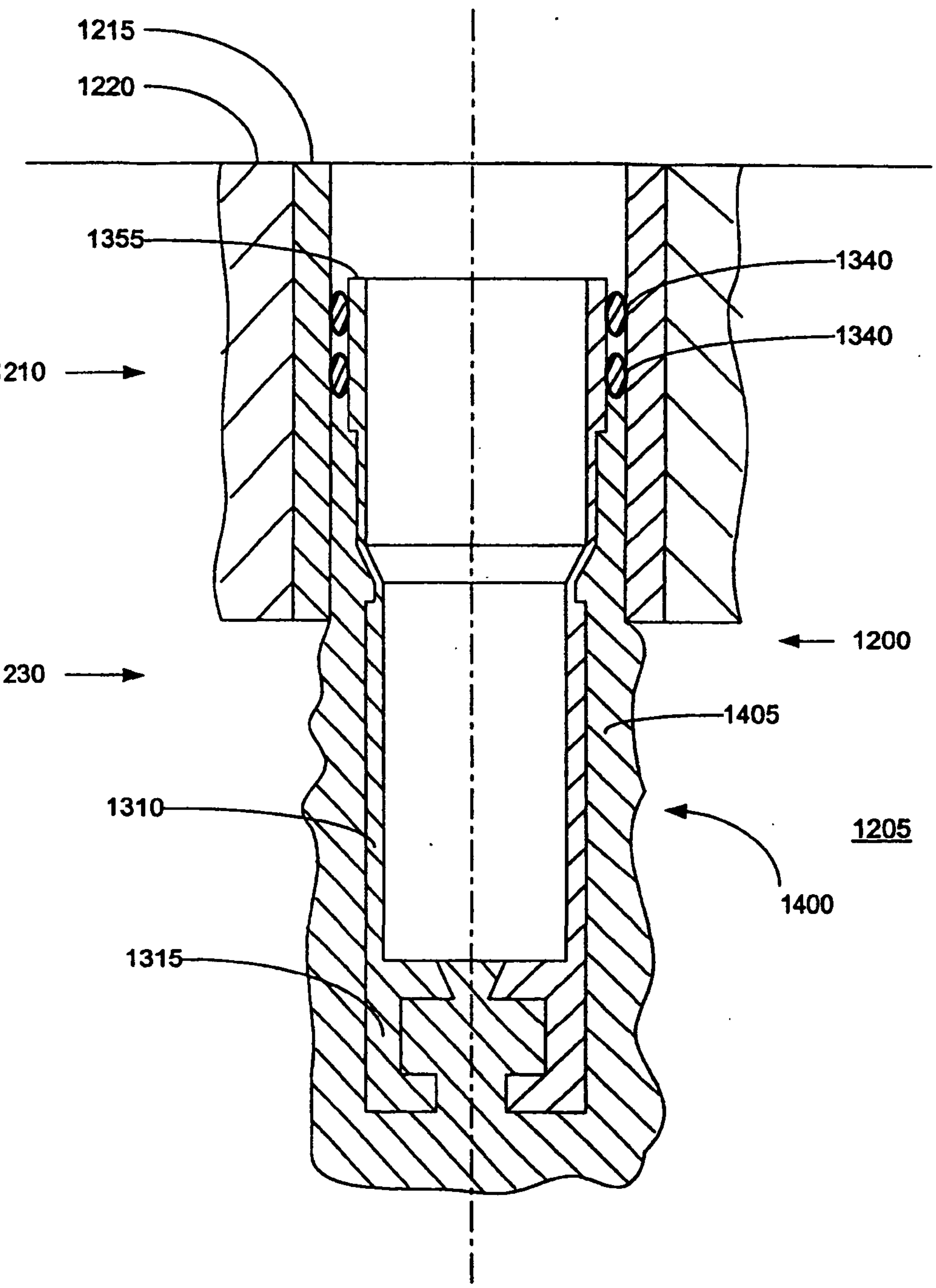
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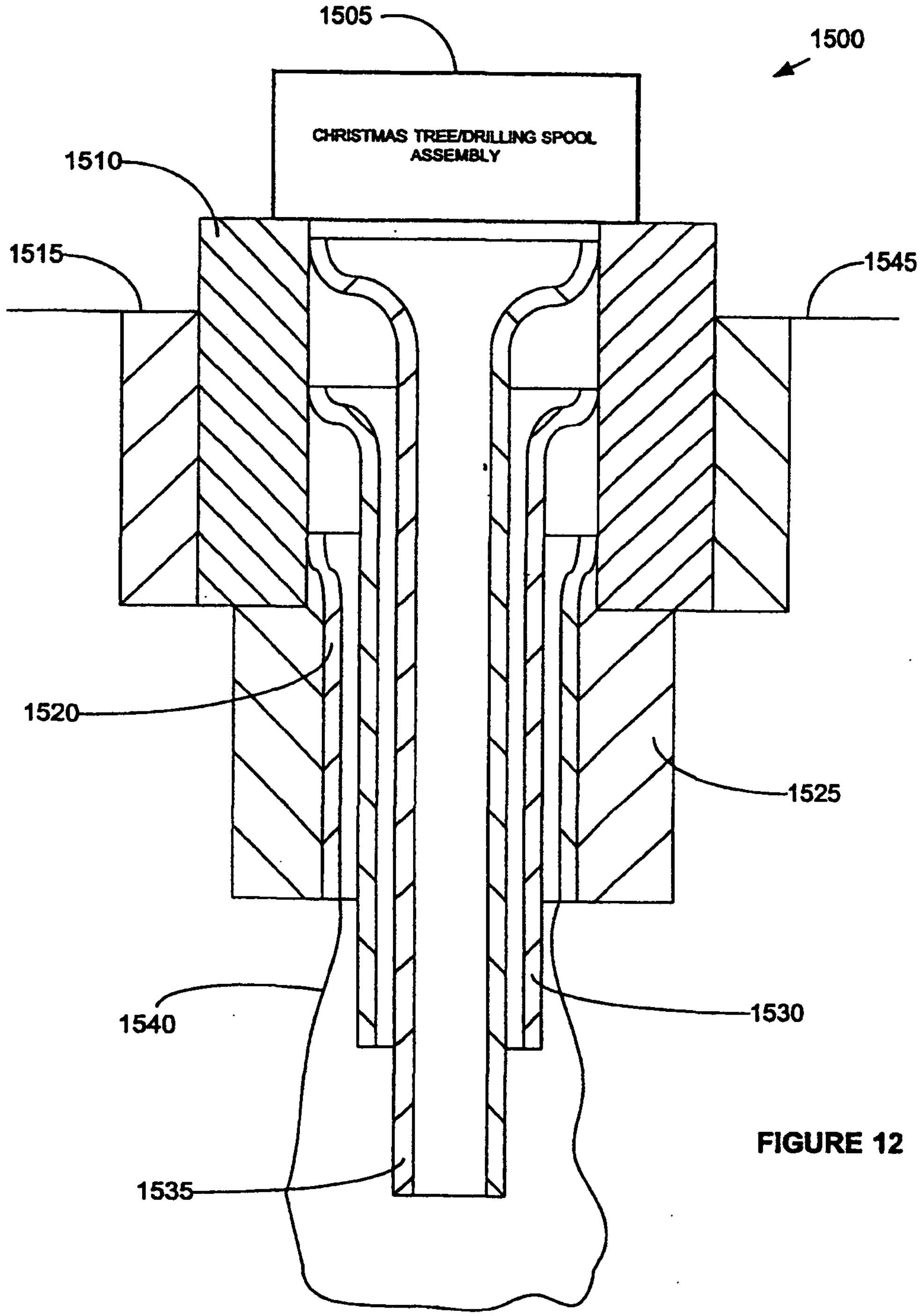
FIGURE 11f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CHRISTMAS TREE/DRILLING SPOOL ASSEMBLY
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FIGURE 12

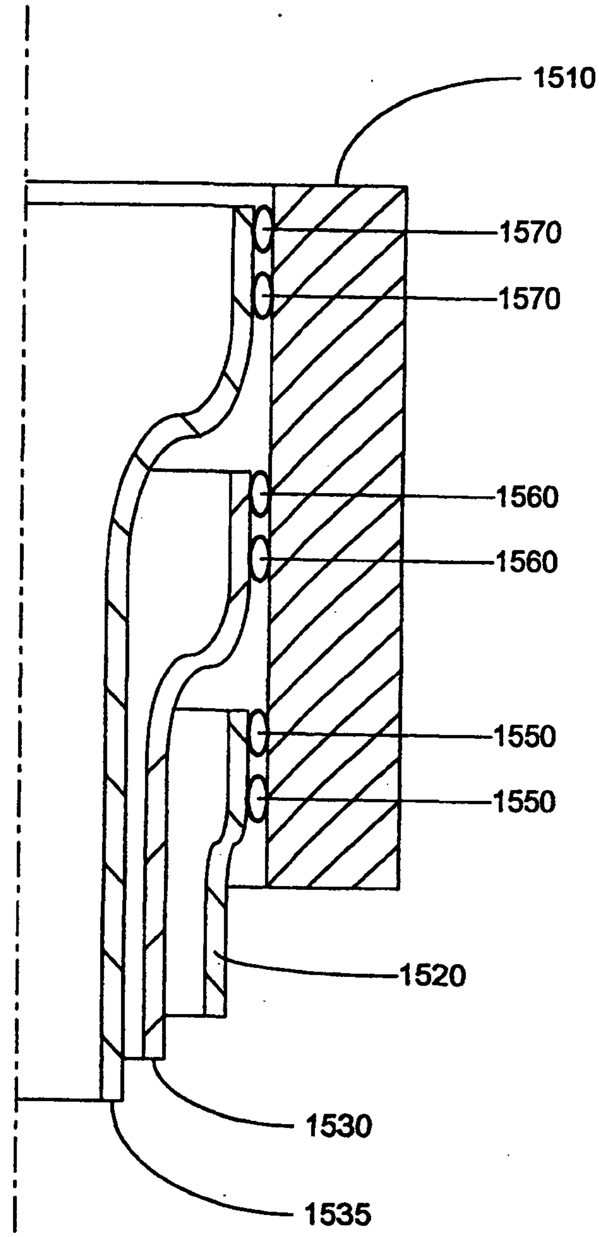

FIGURE 13

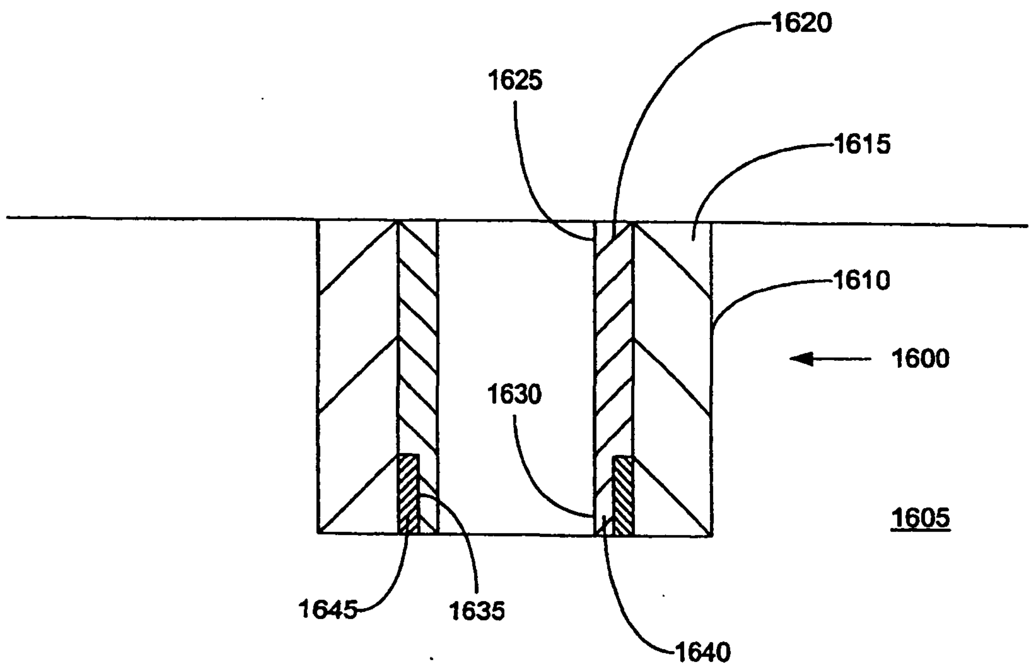

FIGURE 14a

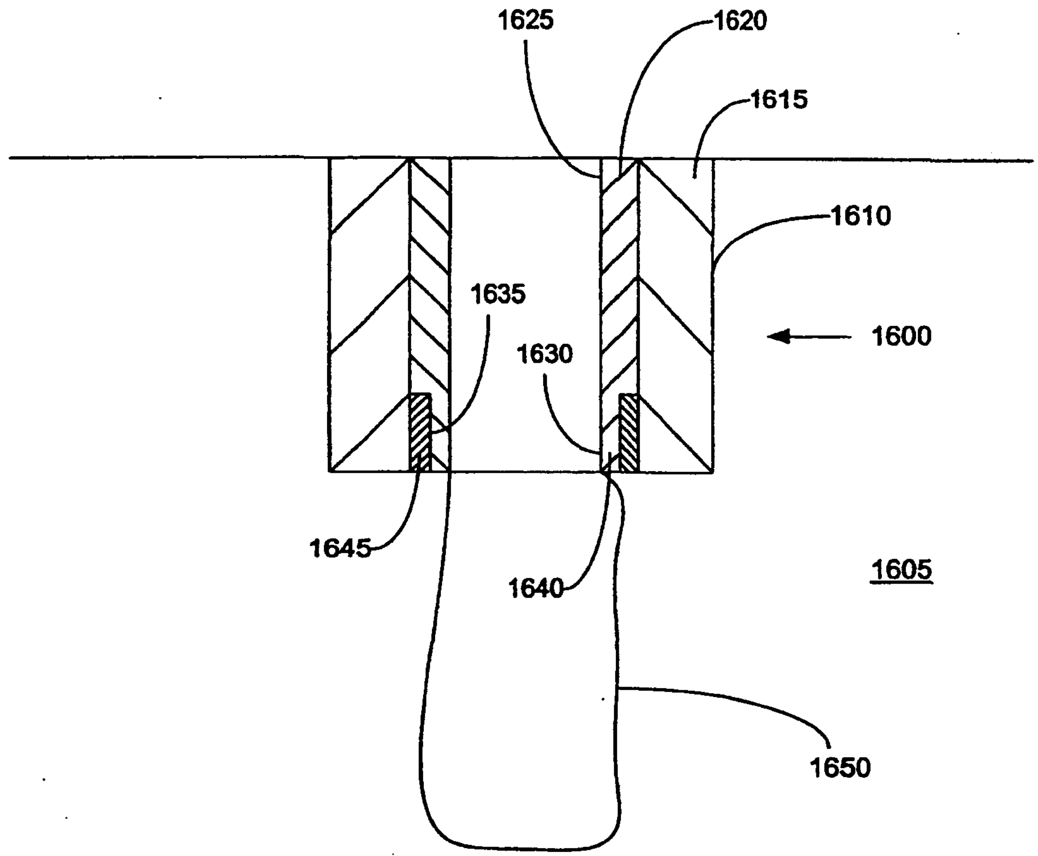

FIGURE 14b

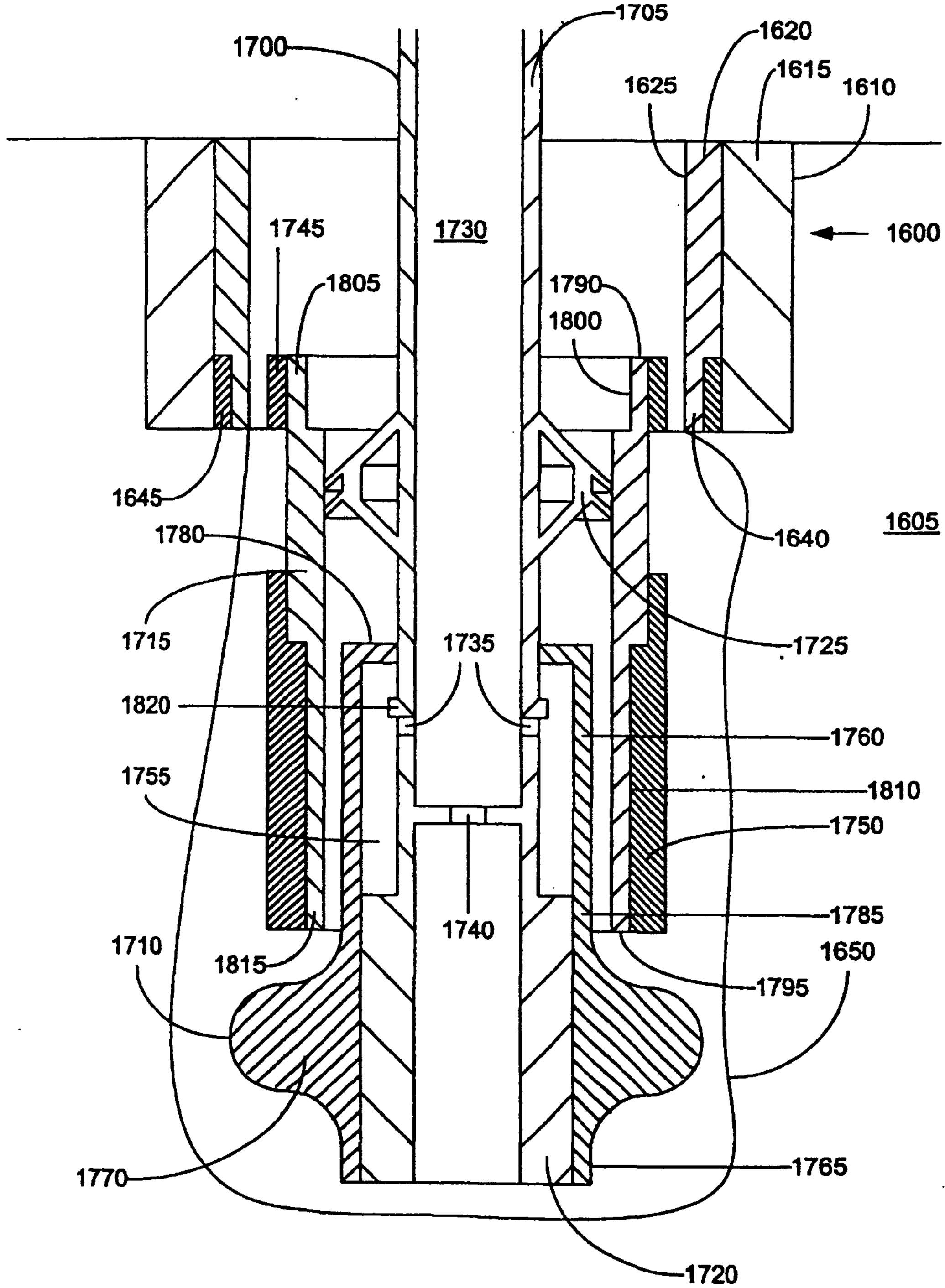
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FIGURE 14c

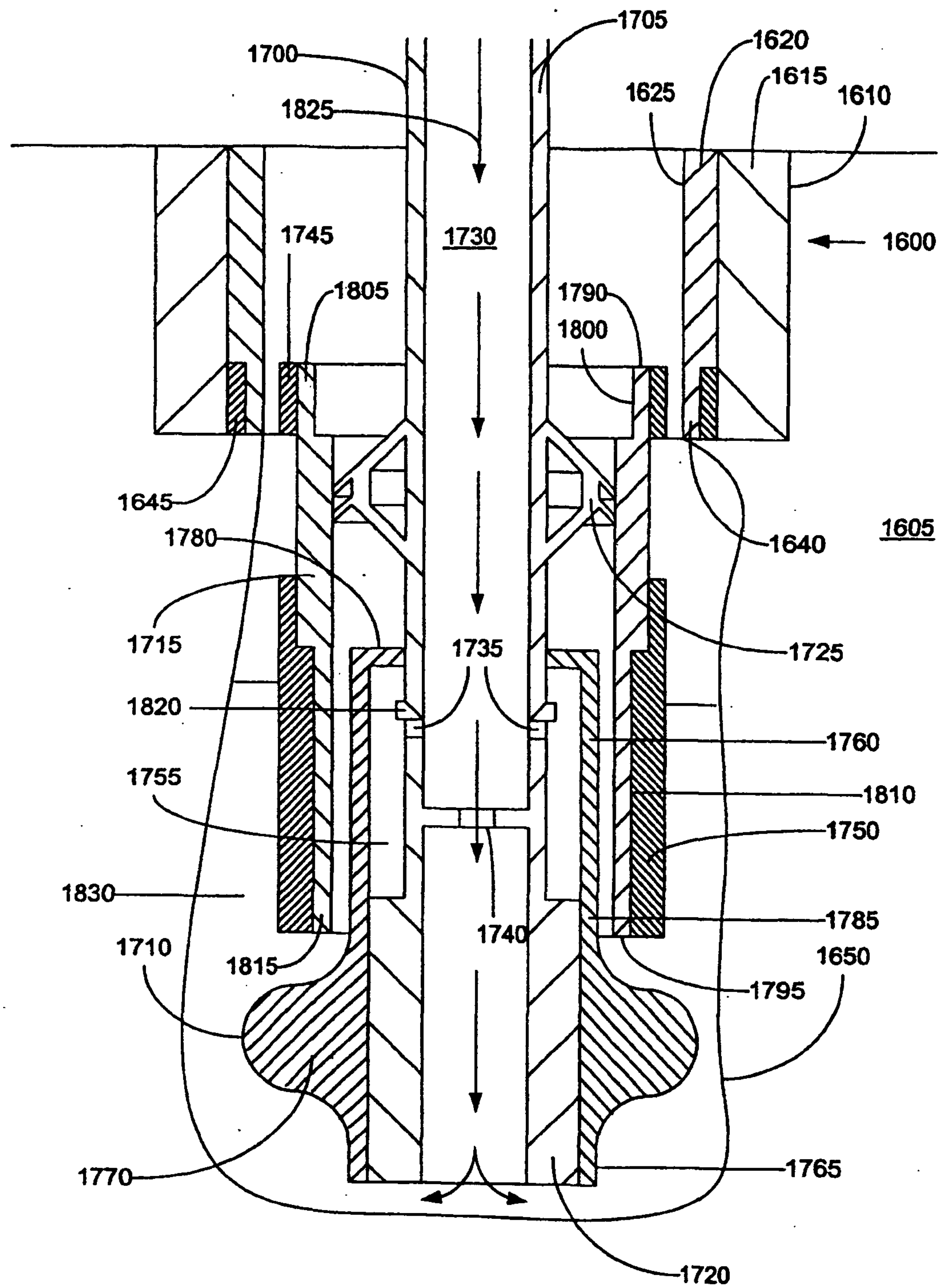
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FIGURE 14d

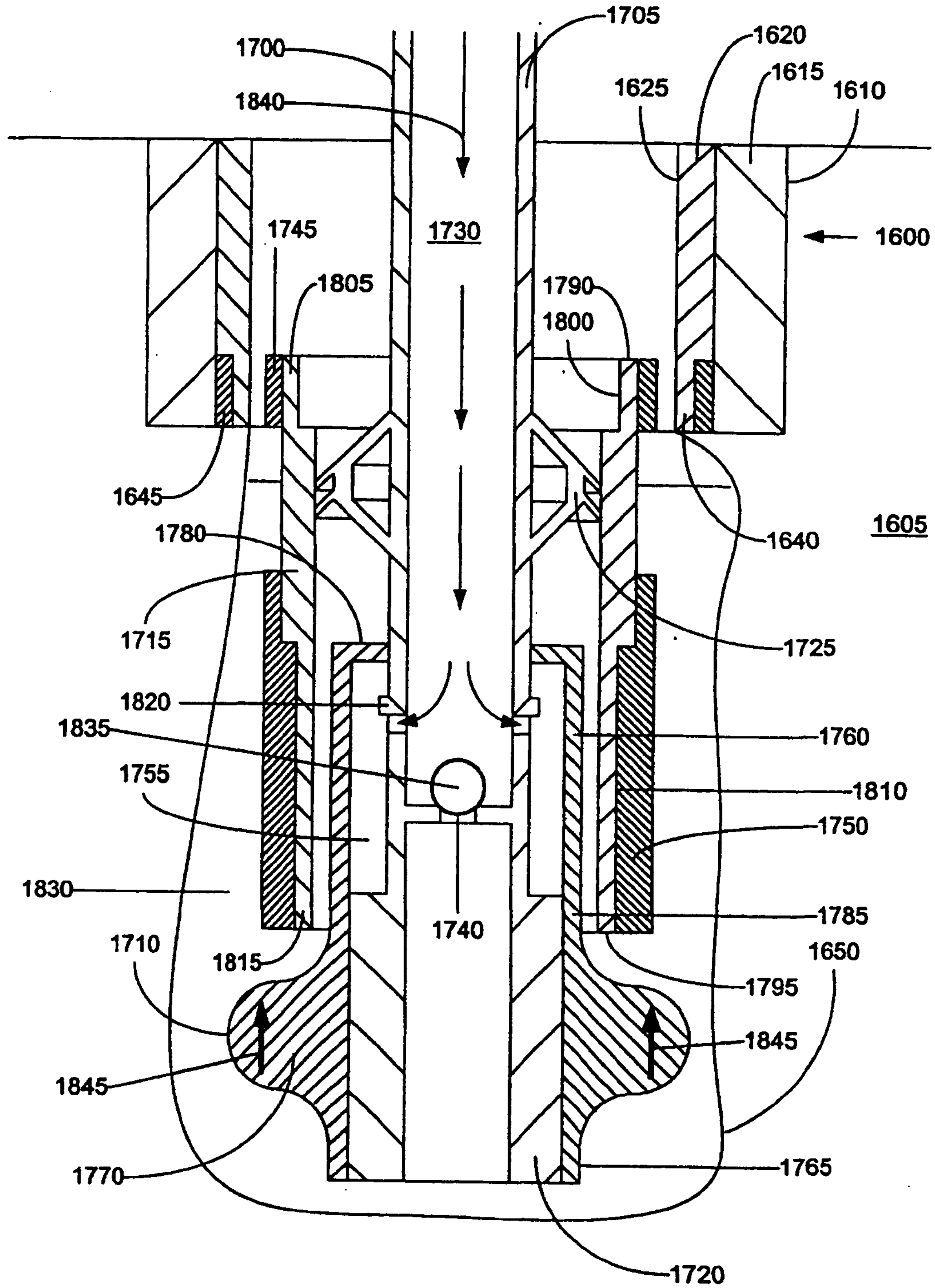
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FIGURE 14e

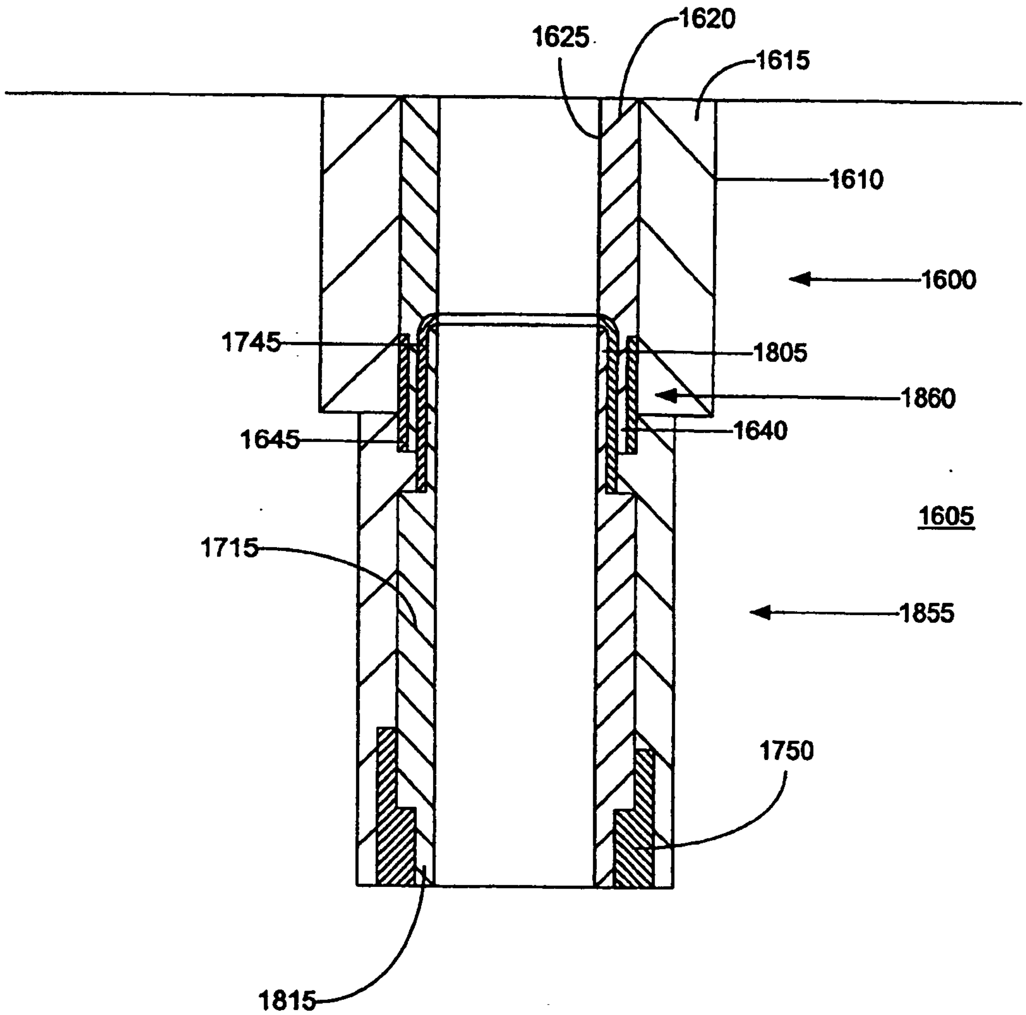
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FIGURE 14f

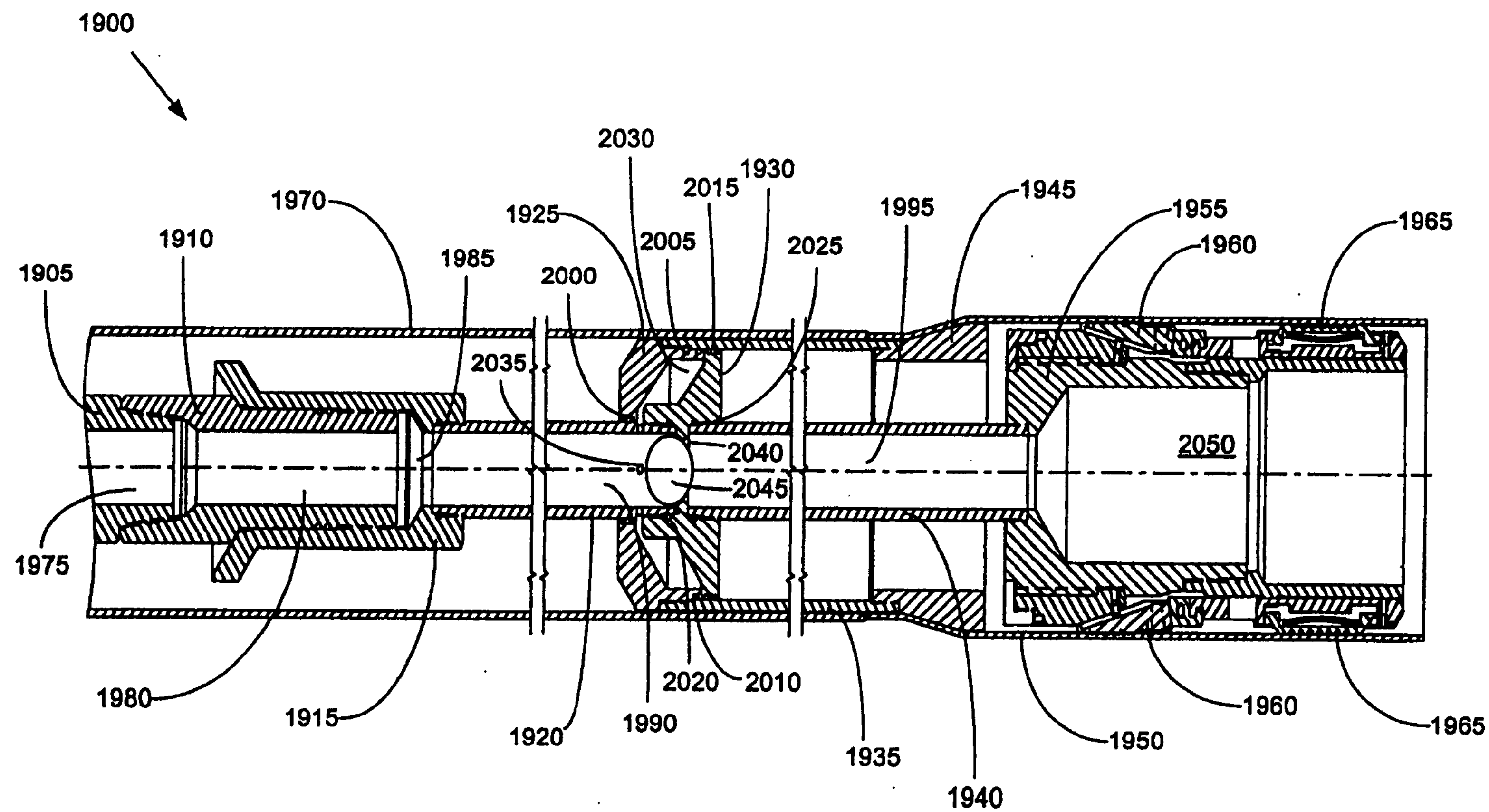
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FIGURE 15

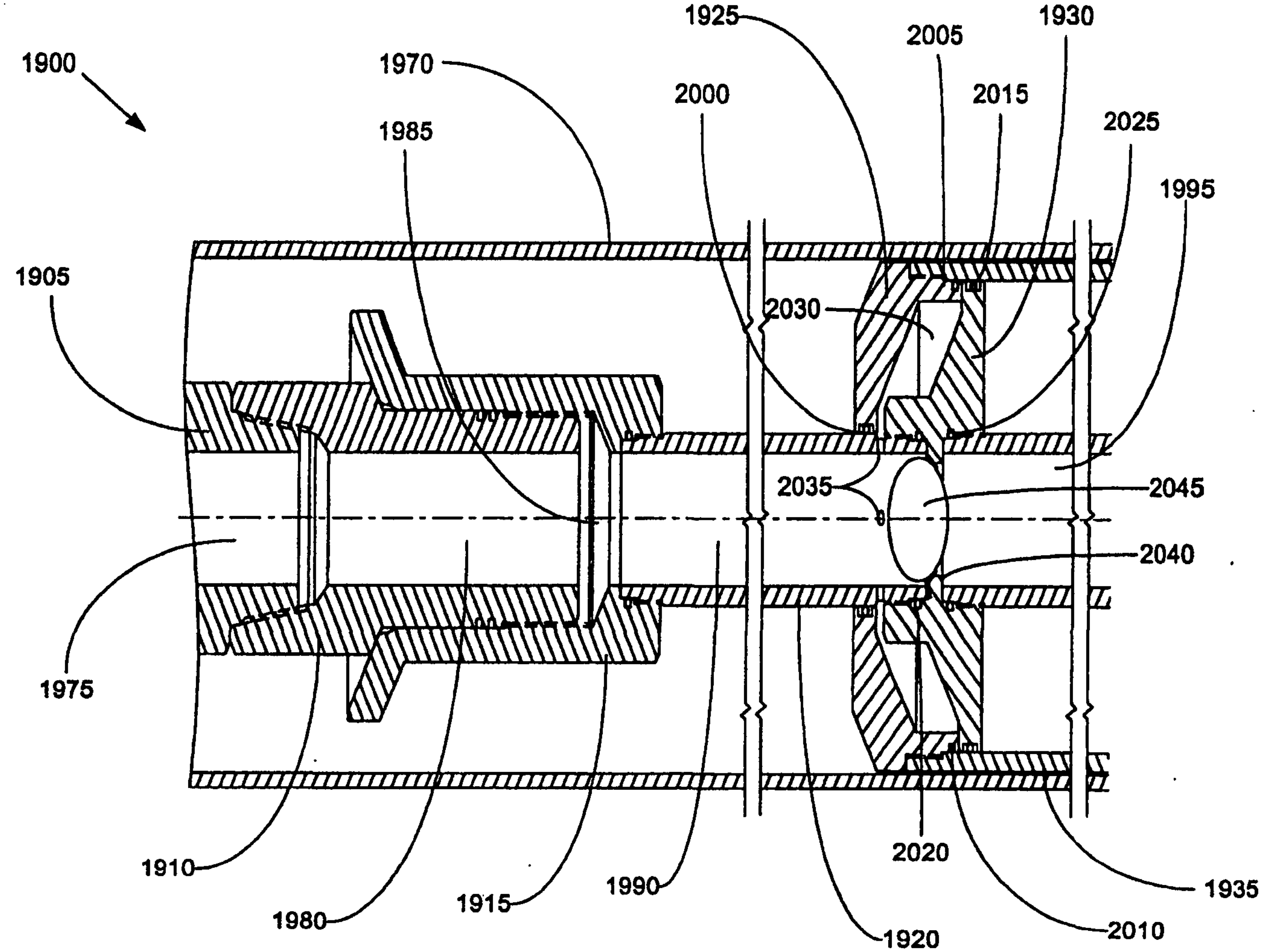
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FIGURE 15a

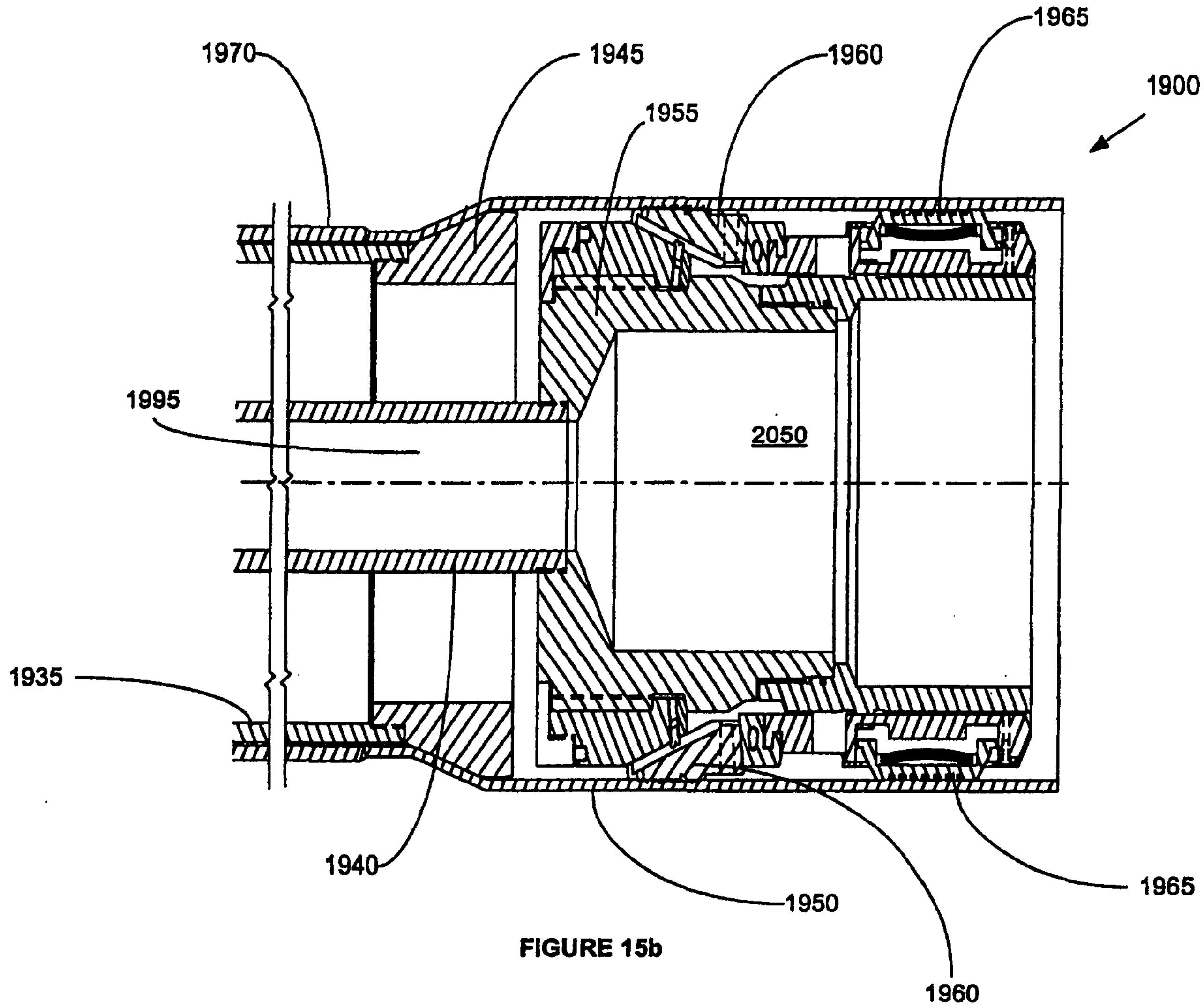
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FIGURE 15b

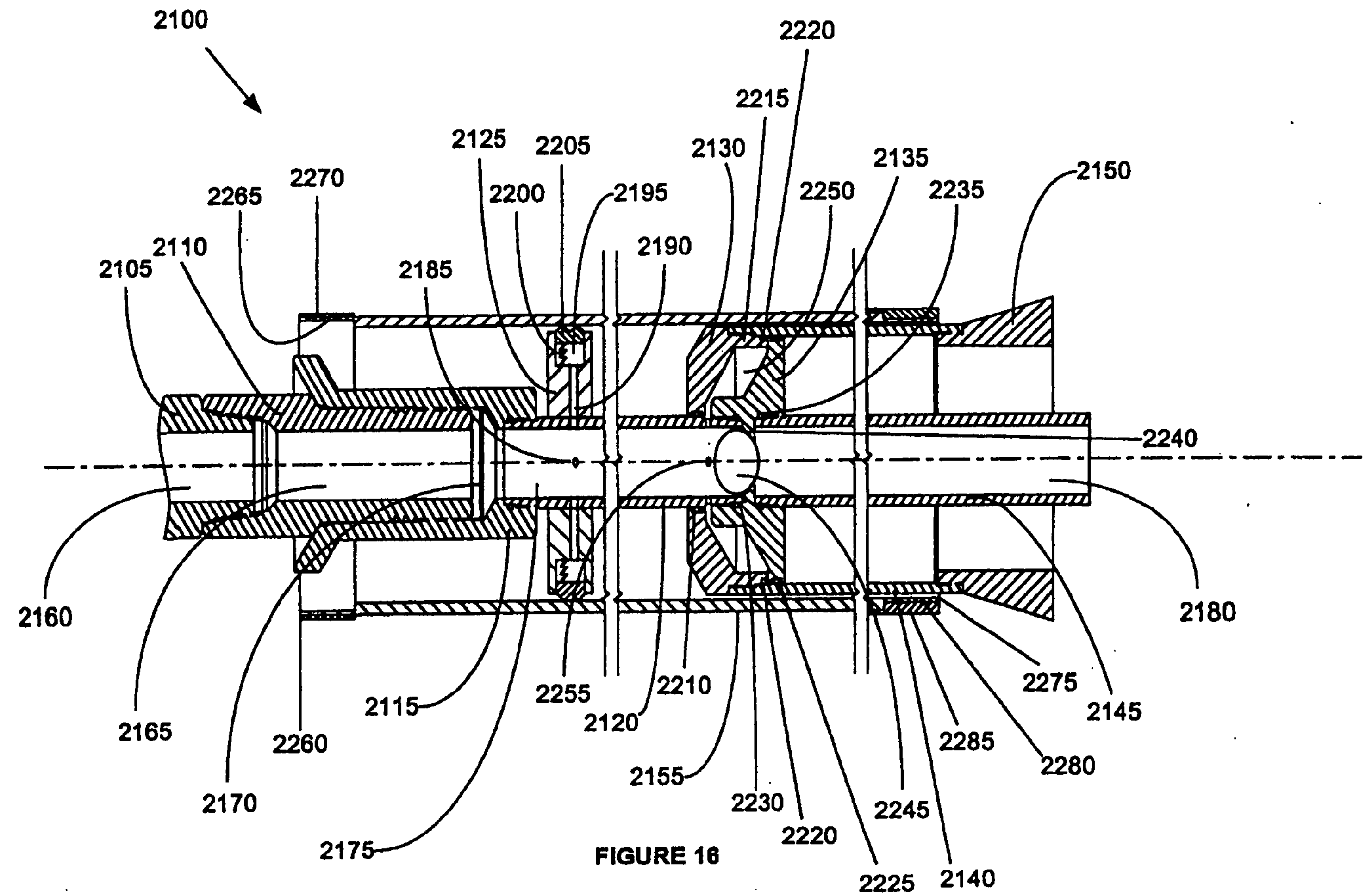
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FIGURE 16

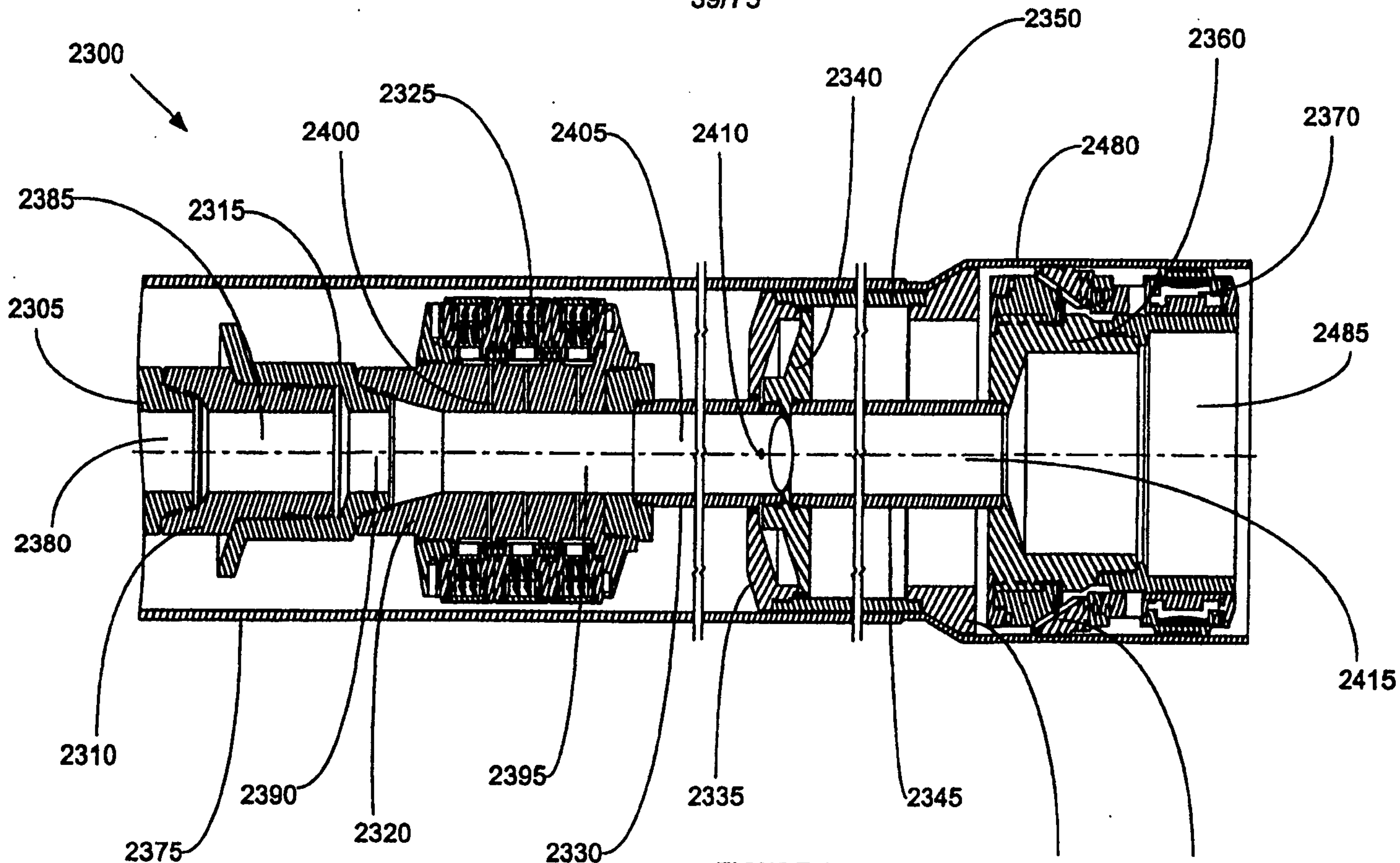
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FIGURE 17

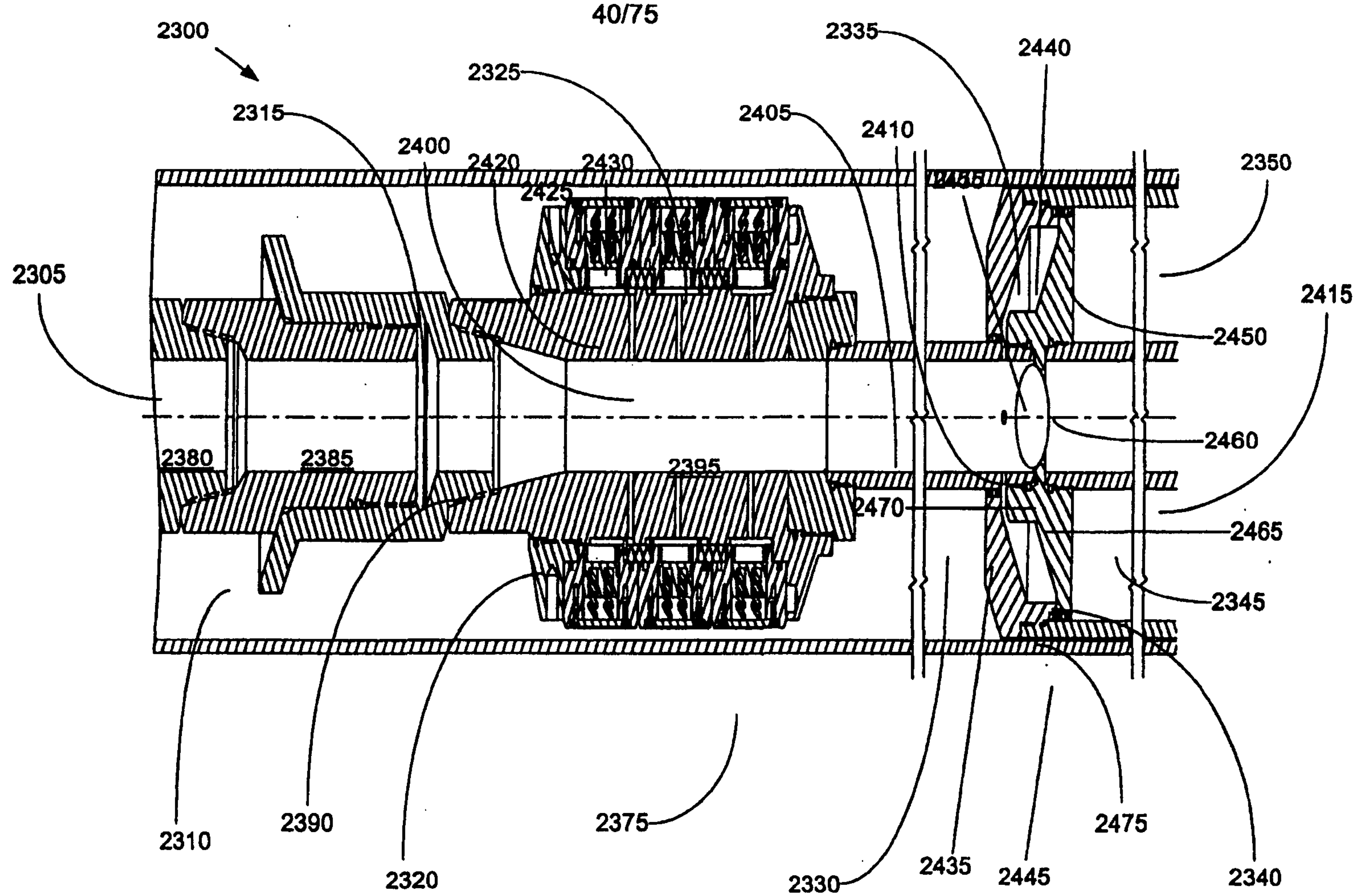
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FIGURE 17a

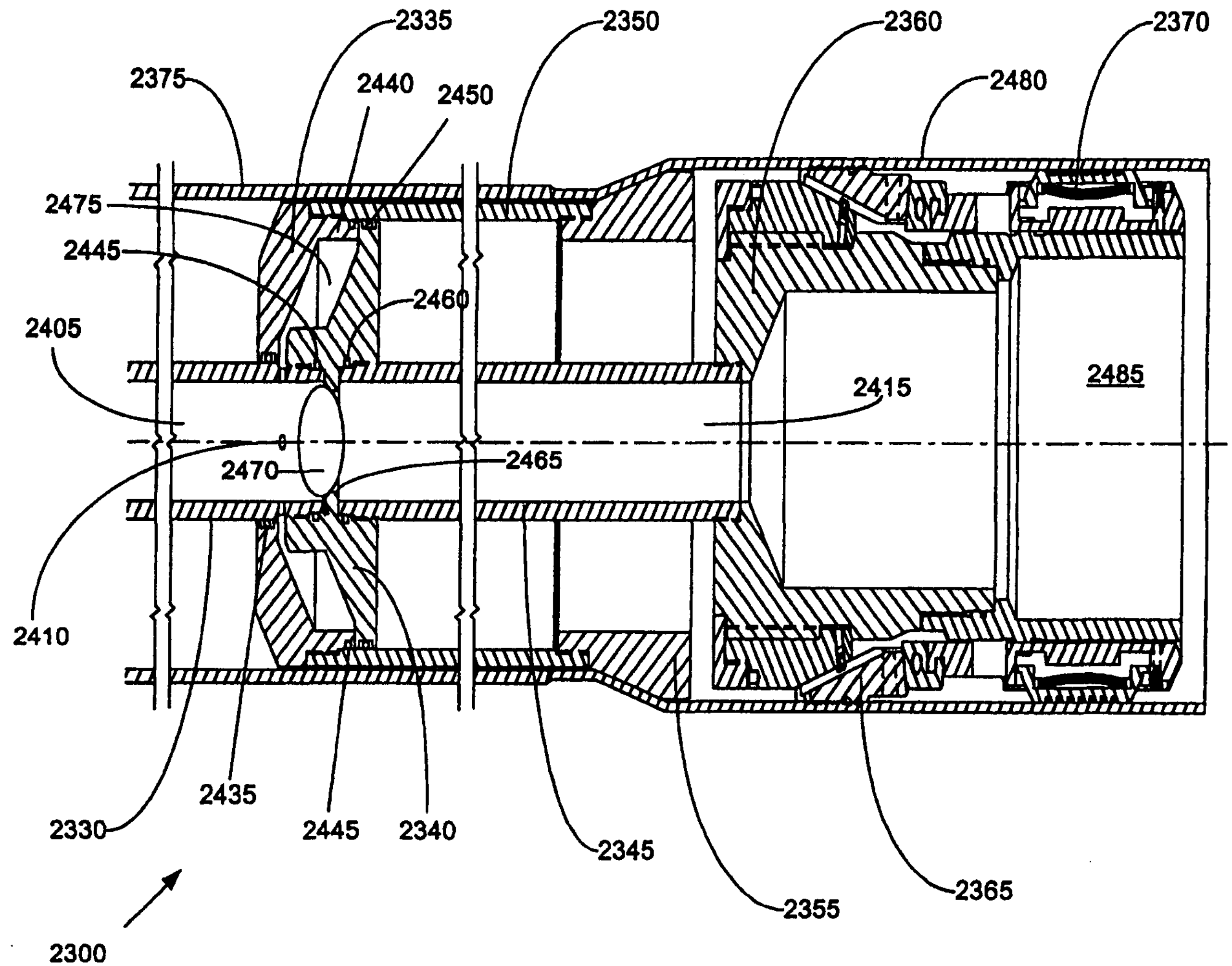
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FIGURE 17b

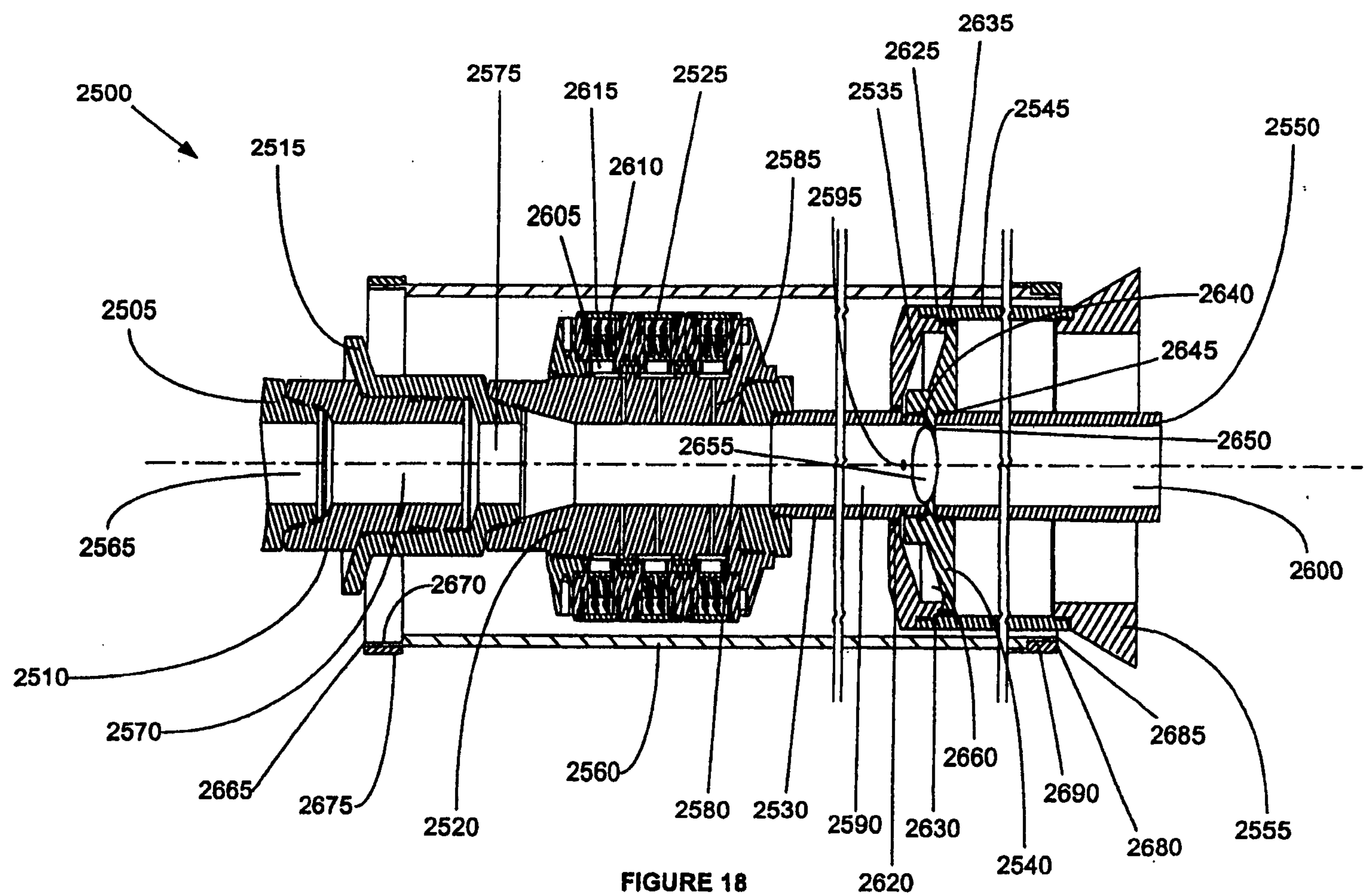
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FIGURE 18

lubricating fluids are injected into the internal flow passages 5420 by pressurizing the area behind the rear 5400b expansion cone 5400 during the radial expansion process.

In a preferred embodiment, the expansion cone 5400 includes a plurality of circumferential grooves 5415. In a preferred embodiment, the cross sectional area of the circumferential grooves 5415 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5400 includes circumferential grooves 5415 that are concentrated about the axial midpoint of the tapered portion 5405 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5415 are equally spaced along the trailing edge portion of the expansion cone 5400 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5400 includes a plurality of axial grooves 5420 coupled to each of the circumferential grooves 5415. In a preferred embodiment, the axial grooves 5420 fluidicly couple the front end and the rear end of the expansion cone 5400. In a preferred embodiment, the cross sectional area of the axial grooves 5420 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2, respectively, in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5415 is greater than the cross sectional area of the axial grooves 5420 in order to minimize resistance to fluid flow. In a preferred embodiment, the axial grooves 5420 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 36, another embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion

predetermined level, a plug 2045, dart, or other similar device is introduced into the first fluidic material. The plug 2045 lodges in the throat passage 2040 thereby fluidicly isolating the fluid passage 1990 from the fluid passage 1995.

After placement of the plug 2045 in the throat passage 2040, a second fluidic material is pumped into the fluid passage 1975 in order to pressurize the pressure chamber 2030. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. The second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant in order minimize frictional forces.

The second fluidic material may be pumped into the apparatus 1900 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. The second fluidic material is pumped into the apparatus 1900 at operating pressures and flow rates ranging from about 0 to 3,500 psi, and 0 to 1,200 gallons/minute in order to optimally provide expansion of the casing 1970.

The pressurization of the pressure chamber 2030 causes the upper sealing head 1925, outer sealing mandrel 1935, and expansion cone 1945 to move in an axial direction. As the expansion cone 1945 moves in the axial direction, the expansion cone 1945 pulls the mandrel launcher 1950 and drag blocks 1965 along, which sets the mechanical slips 1960 and stops further axial movement of the mandrel launcher 1950 and casing 1970. In this manner, the axial movement of the expansion cone 1945 radially expands the mandrel launcher 1950 and casing 1970.

Once the upper sealing head 1925, outer sealing mandrel 1935, and expansion cone 1945 complete an axial stroke, the operating pressure of the second fluidic material is reduced and the drill string 1905 is raised. This causes the inner sealing mandrel 1920, lower sealing head 1930, load mandrel 1940, and mechanical slip body 1955 to move upward. This unsets the mechanical slips 1960 and permits the mechanical slips 1960 and drag blocks 1965 to be moved upward within the mandrel launcher and casing 1970. When the lower sealing head 1930 contacts the upper sealing head 1925, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher 1950 and casing 1970 are radial expanded through repeated axial strokes of the upper sealing head

1925, outer sealing mandrel 1935 and expansion cone 1945. Throughput the radial expansion process, the upper end of the casing 1970 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 1970 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. The sealing members provided at the upper end of the casing 1970 provide a fluidic seal between the outside surface of the upper end of the casing 1970 and the inside surface of the lower end of the existing wellbore casing. The contact pressure between the casing 1970 and the existing section of wellbore casing ranges from about 400 to 10,000 psi in order to optimally provide contact pressure for activating sealing members, provide optimal resistance to axial movement of the expanded casing 1970, and optimally support typical tensile and compressive loads.

As the expansion cone 1945 nears the end of the casing 1970, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 1900. The apparatus 1900 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 1970.

The reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 1945 nears the end of the casing 1970 in order to optimally provide reduced axial movement and velocity of the expansion cone 1945. The operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 1900 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 1945. The stroke length of the apparatus 1900 ranges from about 10 to 45 feet in order to optimally provide equipment lengths that can be handled by typical oil well rigging equipment while also minimizing the frequency at which the expansion cone 1945 must be stopped so the apparatus 1900 can be re-stroked for further expansion operations.

At least a portion of the upper sealing head 1925 includes an expansion cone for radially expanding the mandrel launcher 1950 and casing 1970 during operation of the apparatus 1900 in order to increase the surface area of the casing 1970 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

10 to 45 ft (3,048 metres to 13,716 metres)

0.005 to 0.125 inches (0,000127 to 0,0003175 metres)

500 to 40,000 psi (351.550,00 to 28.124.000,00 Kg/m^2)

0 to 9,000 psi and 0 to 5,000 gallons/minute (0 to 6.327.900,00 Kg/m^2 and 0 to 79.264,426 litres/sec.)

10 to 45 ft (3,048 metres to 13,716 metres)

0 to 10,000 psi and 0 to 3,000 gallons/minute (0 to 7.031.000,00 Kg/m^2 and 0 to 189,24 litres/sec.)

0 to 12,000 psi and 0 to 3,500 gallons/minute (0 to 8.437.200,00 Kg/m^2 and 0 to 220,78 litres/sec)

0 to 12,000 psi and 0 to 10,000 gallons/minute (0 to 8.437.200,00 Kg/m^2 and 0 to 630,80 litres/sec)

0 to 5,000 psi and 40 to 3,000 gallons/minute (0 to 3.515.500,00 Kg/m^2 and 2,5232 to 189,24 litres/sec)

1,000 to 9,000 psi (703.100,00 to 6.327.900,00 Kg/m^2)

3 to 15.5 inches (0,0762 to 0,3937 metres)

3.5 to 16 inches (0,0889 to 0,4064 metres)

0 to 9,000 psi (0 to 6.327.900,00 Kg/m^2)

0 to 3,000 gallons/minute (0 to 189,24 litres/sec.)

of the tubular members beyond the mandrel is pressurized to pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the first tubular member comprises a production casing. In a preferred embodiment, the contact between the first tubular member and the outer casing is sealed. In a preferred embodiment, the contact between the second tubular member and the outer casing is sealed. In a preferred embodiment, the expanded first tubular member is supported using the outer casing. In a preferred embodiment, the expanded second tubular member is supported using the outer casing. In a preferred embodiment, the integrity of the seal in the contact between the first tubular member and the outer casing is tested. In a preferred embodiment, the integrity of the seal in the contact between the second tubular member and the outer casing is tested. In a preferred embodiment, the mandrel is caught upon the completion of the extruding. In a preferred embodiment, the mandrel is drilled out. In a preferred embodiment, the mandrel is supported with coiled tubing. In a preferred embodiment, the mandrel is coupled to a drillable shoe.

An apparatus has also been described that includes an outer tubular member, and a plurality of substantially concentric and overlapping inner tubular members coupled to the outer tubular member. Each inner tubular member is supported by contact pressure between an outer surface of the inner casing and an inner surface of the outer inner tubular member. In a preferred embodiment, the outer tubular member has a yield strength ranging from about 40,000 to 135,000 psi. In a preferred embodiment, the outer tubular member has a burst strength ranging from about 5,000 to 20,000 psi. In a preferred embodiment, the contact pressure between the inner tubular members and the outer tubular member ranges from about 500 to 10,000 psi. In a preferred embodiment, one or more of the inner tubular members include one or more sealing members that contact with an inner surface of the outer tubular member. In a preferred embodiment, the sealing members are selected from the group consisting of rubber, lead, plastic, and epoxy.

4310 during and upon the completion of the radial expansion process is minimized.

The O-ring 4325 is supported by the O-ring groove 4320. The O-ring 4325 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4305 and the second tubular member 4310 throughout and upon the completion of the radial expansion process.

Referring to FIG. 28, an alternative embodiment of an expandable threaded connection 4500 will now be described. The expandable threaded connection 4500 includes a first tubular member 4505, a second tubular member 4510, a threaded connection 4515, an O-ring groove 4520, and an O-ring 4525.

The first tubular member 4505 includes an inside wall 4530 and an outside wall 4535. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4510 includes an inside wall 4540 and an outside wall 4545. The second tubular member 4510 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4505 and 4510, may comprise any number of conventional commercially available members. In a preferred embodiment, the inside and outside diameters of the first and second tubular members, 4505 and 4510, are substantially equal. In this manner, the burst strength of the tubular members, 4505 and 4510, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4515 may comprise any number of conventional threaded connections suitable for use with tubular members. In a preferred embodiment, the threaded connection 4515 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4505 to the second tubular member 4510 is optimized.

The O-ring groove 4520 is preferably provided in the threaded portion of the interior wall 4540 of the second tubular member 4510 immediately adjacent to an end

portion of the threaded connection 4515. In this manner, the sealing effect provided by the O-ring 4525 is optimized. The O-ring groove 4520 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4520 is preferably selected to permit the O-ring 4525 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4545 of the second tubular member 4510 during and upon the completion of the radial expansion process is minimized.

The O-ring 4525 is supported by the O-ring groove 4520. The O-ring 4525 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4505 and the second tubular member 4510 throughout and upon the completion of the radial expansion process.

Referring to FIG. 29, an alternative embodiment of an expandable threaded connection 4700 will now be described. The expandable threaded connection 4700 includes a first tubular member 4705, a second tubular member 4710, a threaded connection 4715, an O-ring groove 4720, a first O-ring 4725, and a second O-ring 4730.

The first tubular member 4705 includes an inside wall 4735 and an outside wall 4740. The first tubular member 4705 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4710 includes an inside wall 4745 and an outside wall 4750. The second tubular member 4710 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4705 and 4710, may comprise any number of conventional commercially available members. In a preferred embodiment, the inside and outside diameters of the first and second tubular members, 4705 and 4710, are substantially equal. In this manner, the burst strength of the tubular members, 4705 and 4710, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

2335 and the outer surface of the inner sealing mandrel 2330 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 2335 and the outer surface of the inner sealing mandrel 2330 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal clearance. The radial clearance between the outer cylindrical surface of the upper sealing head 2335 and the inner surface of the casing 2375 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 2335 and the inner surface of the casing 2375 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2355 during the expansion process.

The upper sealing head 2335 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 2335 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the upper sealing head 2335 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the upper sealing head 2335 preferably includes one or more annular sealing members 2435 for sealing the interface between the upper sealing head 2335 and the inner sealing mandrel 2330. The sealing members 2435 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2435 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the upper sealing head 2335 includes a shoulder 2440 for supporting the upper sealing head on the lower sealing head 1930.

The upper sealing head 2335 may be coupled to the outer sealing mandrel 2350 using any number of conventional commercially available mechanical couplings such

as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the upper sealing head 2335 is removably coupled to the outer sealing mandrel 2350 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the upper sealing head 2335 and the outer sealing mandrel 2350 includes one or more sealing members 2445 for fluidicly sealing the interface between the upper sealing head 2335 and the outer sealing mandrel 2350. The sealing members 2445 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2445 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The lower sealing head 2340 is coupled to the inner sealing mandrel 2330 and the load mandrel 2345. The lower sealing head 2340 is also movably coupled to the inner surface of the outer sealing mandrel 2350. In this manner, the upper sealing head 2335 and outer sealing mandrel 2350 reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head 2340 and the inner surface of the outer sealing mandrel 2350 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the lower sealing head 2340 and the inner surface of the outer sealing mandrel 2350 ranges from about 0.005 to 0.010 inches in order to optimally provide minimal radial clearance.

The lower sealing head 2340 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 2340 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubular members, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the lower sealing head 2340 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the

lower sealing head 2340 preferably includes one or more annular sealing members 2450 for sealing the interface between the lower sealing head 2340 and the outer sealing mandrel 2350. The sealing members 2450 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2450 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2340 may be coupled to the inner sealing mandrel 2330 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular specialty threaded connection, welding, amorphous bonding, or standard threaded connection. In a preferred embodiment, the lower sealing head 2340 is removably coupled to the inner sealing mandrel 2330 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2340 and the inner sealing mandrel 2330 includes one or more sealing members 2455 for fluidicly sealing the interface between the lower sealing head 2340 and the inner sealing mandrel 2330. The sealing members 2455 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak or metal spring energized seals. In a preferred embodiment, the sealing members 2455 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

The lower sealing head 2340 may be coupled to the load mandrel 2345 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the lower sealing head 2340 is removably coupled to the load mandrel 2345 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2340 and the load mandrel 2345 includes one or more sealing members 2460 for fluidicly sealing the interface between

the lower sealing head 2340 and the load mandrel 2345. The sealing members 2460 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2460 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

In a preferred embodiment, the lower sealing head 2340 includes a throat passage 2465 fluidicly coupled between the fluid passages 2405 and 2415. The throat passage 2465 is preferably of reduced size and is adapted to receive and engage with a plug 2470, or other similar device. In this manner, the fluid passage 2405 is fluidicly isolated from the fluid passage 2415. In this manner, the pressure chamber 2475 is pressurized.

The outer sealing mandrel 2350 is coupled to the upper sealing head 2335 and the expansion cone 2355. The outer sealing mandrel 2350 is also movably coupled to the inner surface of the casing 2375 and the outer surface of the lower sealing head 2340. In this manner, the upper sealing head 2335, outer sealing mandrel 2350, and the expansion cone 2355 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel 2350 and the inner surface of the casing 2375 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the outer sealing mandrel 2350 and the inner surface of the casing 2375 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2355 during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel 2350 and the outer surface of the lower sealing head 2340 may range, for example, from about 0.0025 to 0.375 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing mandrel 2350 and the outer surface of the lower sealing head 2340 ranges from about 0.005 to 0.010 inches in order to optimally provide minimal clearance.

The outer sealing mandrel 2350 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel

2350 may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the outer sealing mandrel 2350 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel 2350 may be coupled to the upper sealing head 2335 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connections, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2350 is removably coupled to the upper sealing head 2335 by a standard threaded connection. The outer sealing mandrel 2350 may be coupled to the expansion cone 2355 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2350 is removably coupled to the expansion cone 2355 by a standard threaded connection.

The upper sealing head 2335, the lower sealing head 2340, the inner sealing mandrel 2330, and the outer sealing mandrel 2350 together define a pressure chamber 2475. The pressure chamber 2475 is fluidicly coupled to the passage 2405 via one or more passages 2410. During operation of the apparatus 2300, the plug 2470 engages with the throat passage 2465 to fluidicly isolate the fluid passage 2415 from the fluid passage 2405. The pressure chamber 2475 is then pressurized which in turn causes the upper sealing head 2335, outer sealing mandrel 2350, and expansion cone 2355 to reciprocate in the axial direction. The axial motion of the expansion cone 2355 in turn expands the casing 2375 in the radial direction.

The load mandrel 2345 is coupled to the lower sealing head 2340 and the mechanical slip body 2360. The load mandrel 2345 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel

2345 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 2345 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 2345 may be coupled to the lower sealing head 2340 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the load mandrel 2345 is removably coupled to the lower sealing head 2340 by a standard threaded connection. The load mandrel 2345 may be coupled to the mechanical slip body 2360 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the load mandrel 2345 is removably coupled to the mechanical slip body 2360 by a standard threaded connection.

The load mandrel 2345 preferably includes a fluid passage 2415 that is adapted to convey fluidic materials from the fluid passage 2405 to the region outside of the apparatus 2300. In a preferred embodiment, the fluid passage 2415 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 2355 is coupled to the outer sealing mandrel 2350. The expansion cone 2355 is also movably coupled to the inner surface of the casing 2375. In this manner, the upper sealing head 2335, outer sealing mandrel 2350, and the expansion cone 2355 reciprocate in the axial direction. The reciprocation of the expansion cone 2355 causes the casing 2375 to expand in the radial direction.

drillpipe 2305 may be coupled to the innerstring adapter 2310 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2305 is removably coupled to the innerstring adapter 2310 by a drillpipe connection.

The drillpipe 2305 preferably includes a fluid passage 2380 that is adapted to convey fluidic materials from a surface location into the fluid passage 2385. In a preferred embodiment, the fluid passage 2380 is adapted to convey fluidic materials such as, for example, cement, water, epoxy, drilling muds, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 5,000 gallons/minute in order to optimally provide operational efficiency.

The innerstring adapter 2310 is coupled to the drill string 2305 and the sealing sleeve 2315. The innerstring adapter 2310 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2310 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the innerstring adapter 2310 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 2310 may be coupled to the drill string 2305 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2310 is removably coupled to the drill pipe 2305 by a drillpipe connection. The innerstring adapter 2310 may be coupled to the sealing sleeve 2315 using any number of conventional commercially available mechanical couplings such as, for example, a drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment,

the innerstring adapter 2310 is removably coupled to the sealing sleeve 2315 by a standard threaded connection.

The innerstring adapter 2310 preferably includes a fluid passage 2385 that is adapted to convey fluidic materials from the fluid passage 2380 into the fluid passage 2390. In a preferred embodiment, the fluid passage 2385 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, drilling gases or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 2315 is coupled to the innerstring adapter 2310 and the hydraulic slip body 2320. The sealing sleeve 2315 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 2315 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2315 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low-friction surfaces.

The sealing sleeve 2315 may be coupled to the innerstring adapter 2310 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connections, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2315 is removably coupled to the innerstring adapter 2310 by a standard threaded connection. The sealing sleeve 2315 may be coupled to the hydraulic slip body 2320 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2315 is removably coupled to the hydraulic slip body 2320 by a standard threaded connection.

The sealing sleeve 2315 preferably includes a fluid passage 2390 that is adapted to convey fluidic materials from the fluid passage 2385 into the fluid passage 2395.

In a preferred embodiment, the fluid passage 2315 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slip body 2320 is coupled to the sealing sleeve 2315, the hydraulic slips 2325, and the inner sealing mandrel 2330. The hydraulic slip body 2320 preferably comprises a substantially hollow tubular member or members. The hydraulic slip body 2320 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other high strength material. In a preferred embodiment, the hydraulic slip body 2320 is fabricated from carbon steel in order to optimally provide high strength at low cost.

The hydraulic slip body 2320 may be coupled to the sealing sleeve 2315 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2320 is removably coupled to the sealing sleeve 2315 by a standard threaded connection. The hydraulic slip body 2320 may be coupled to the slips 2325 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2320 is removably coupled to the slips 2325 by a standard threaded connection. The hydraulic slip body 2320 may be coupled to the inner sealing mandrel 2330 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2320 is removably coupled to the inner sealing mandrel 2330 by a standard threaded connection.

The hydraulic slips body 2320 preferably includes a fluid passage 2395 that is adapted to convey fluidic materials from the fluid passage 2390 into the fluid passage 2405. In a preferred embodiment, the fluid passage 2395 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slips body 2320 preferably includes fluid passage 2400 that are adapted to convey fluidic materials from the fluid passage 2395 into the pressure chambers 2420 of the hydraulic slips 2325. In this manner, the slips 2325 are activated upon the pressurization of the fluid passage 2395 into contact with the inside surface of the casing 2375. In a preferred embodiment, the fluid passages 2400 are adapted to convey fluidic materials such as, for example, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips 2325 are coupled to the outside surface of the hydraulic slip body 2320. During operation of the apparatus 2300, the slips 2325 are activated upon the pressurization of the fluid passage 2395 into contact with the inside surface of the casing 2375. In this manner, the slips 2325 maintain the casing 2375 in a substantially stationary position.

The slips 2325 preferably include the fluid passages 2400, the pressure chambers 2420, spring bias 2425, and slip members 2430. The slips 2325 may comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In a preferred embodiment, the slips 2325 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2375 during the radial expansion process.

The inner sealing mandrel 2330 is coupled to the hydraulic slip body 2320 and the lower sealing head 2340. The inner sealing mandrel 2330 preferably comprises

a substantially hollow tubular member or members. The inner sealing mandrel 2330 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the inner sealing mandrel 2330 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The inner sealing mandrel 2330 may be coupled to the hydraulic slip body 2320 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2330 is removably coupled to the hydraulic slip body 2320 by a standard threaded connection. The inner sealing mandrel 2330 may be coupled to the lower sealing head 2340 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2330 is removably coupled to the lower sealing head 2340 by a standard threaded connection.

The inner sealing mandrel 2330 preferably includes a fluid passage 2405 that is adapted to convey fluidic materials from the fluid passage 2395 into the fluid passage 2415. In a preferred embodiment, the fluid passage 2405 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head 2335 is coupled to the outer sealing mandrel 2345 and expansion cone 2355. The upper sealing head 2335 is also movably coupled to the outer surface of the inner sealing mandrel 2330 and the inner surface of the casing 2375. In this manner, the upper sealing head 2335 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head

The expansion cone 2355 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide radial expansion of the typical casings. The axial length of the expansion cone 2355 may range, for example, from about 2 to 8 times the largest outside diameter of the expansion cone 2355. In a preferred embodiment, the axial length of the expansion cone 2355 ranges from about 3 to 5 times the largest outside diameter of the expansion cone 2355 in order to optimally provide stability and centralization of the expansion cone 2355 during the expansion process. In a preferred embodiment, the angle of attack of the expansion cone 2355 ranges from about 5 to 30 degrees in order to optimally frictional forces with radial expansion forces. The optimum angle of attack of the expansion cone 2355 will vary as a function of the operating parameters of the particular expansion operation.

The expansion cone 2355 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In a preferred embodiment, the expansion cone 2355 is fabricated from D2 machine tool steel in order to optimally provide high strength, abrasion resistance, and galling resistance. In a particularly preferred embodiment, the outside surface of the expansion cone 2355 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength, abrasion resistance, resistance to galling.

The expansion cone 2355 may be coupled to the outside sealing mandrel 2350 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the expansion cone 2355 is coupled to the outside sealing

mandrel 2350 using a standard threaded connection in order to optimally provide high strength and permit the expansion cone 2355 to be easily replaced.

The mandrel launcher 2480 is coupled to the casing 2375. The mandrel launcher 2480 comprises a tubular section of casing having a reduced wall thickness compared to the casing 2375. In a preferred embodiment, the wall thickness of the mandrel launcher 2480 is about 50 to 100 % of the wall thickness of the casing 2375. In this manner, the initiation of the radial expansion of the casing 2375 is facilitated, and the placement of the apparatus 2300 into a wellbore casing and wellbore is facilitated.

The mandrel launcher 2480 may be coupled to the casing 2375 using any number of conventional mechanical couplings. The mandrel launcher 2480 may have a wall thickness ranging, for example, from about 0.15 to 1.5 inches. In a preferred embodiment, the wall thickness of the mandrel launcher 2480 ranges from about 0.25 to 0.75 inches in order to optimally provide high strength in a minimal profile. The mandrel launcher 2480 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the mandrel launcher 2480 is fabricated from oilfield tubular goods having a higher strength than that of the casing 2375 but with a smaller wall thickness than the casing 2375 in order to optimally provide a thin walled container having approximately the same burst strength as that of the casing 2375.

The mechanical slip body 2460 is coupled to the load mandrel 2345, the mechanical slips 2365, and the drag blocks 2370. The mechanical slip body 2460 preferably comprises a tubular member having an inner passage 2485 fluidicly coupled to the passage 2415. In this manner, fluidic materials may be conveyed from the passage 2484 to a region outside of the apparatus 2300.

The mechanical slip body 2360 may be coupled to the load mandrel 2345 using any number of conventional mechanical couplings. In a preferred embodiment, the

mechanical slip body 2360 is removably coupled to the load mandrel 2345 using threads and sliding steel retaining rings in order to optimally provide a high strength attachment. The mechanical slip body 2360 may be coupled to the mechanical slips 2365 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2360 is removably coupled to the mechanical slips 2365 using threads and sliding steel retaining rings in order to optimally provide a high strength attachment. The mechanical slip body 2360 may be coupled to the drag blocks 2370 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2360 is removably coupled to the drag blocks 2365 using threads and sliding steel retaining rings in order to optimally provide a high strength attachment.

The mechanical slips 2365 are coupled to the outside surface of the mechanical slip body 2360. During operation of the apparatus 2300, the mechanical slips 2365 prevent upward movement of the casing 2375 and mandrel launcher 2480. In this manner, during the axial reciprocation of the expansion cone 2355, the casing 2375 and mandrel launcher 2480 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2480 and casing 2375 are expanded in the radial direction by the axial movement of the expansion cone 2355.

The mechanical slips 2365 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the mechanical slips 2365 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2375 during the expansion process.

The drag blocks 2370 are coupled to the outside surface of the mechanical slip body 2360. During operation of the apparatus 2300, the drag blocks 2370 prevent upward movement of the casing 2375 and mandrel launcher 2480. In this manner,

during the axial reciprocation of the expansion cone 2355, the casing 2375 and mandrel launcher 2480 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2480 and casing 2375 are expanded in the radial direction by the axial movement of the expansion cone 2355.

The drag blocks 2370 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer mechanical drag blocks or Model 3L retrievable bridge plug drag blocks. In a preferred embodiment, the drag blocks 2370 comprise RTTS packer mechanical drag blocks available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2375 during the expansion process.

The casing 2375 is coupled to the mandrel launcher 2480. The casing 2375 is further removably coupled to the mechanical slips 2365 and drag blocks 2370. The casing 2375 preferably comprises a tubular member. The casing 2375 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oil country tubular goods, carbon steel, low alloy steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 2375 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength. In a preferred embodiment, the upper end of the casing 2375 includes one or more sealing members positioned about the exterior of the casing 2375.

During operation, the apparatus 2300 is positioned in a wellbore with the upper end of the casing 2375 positioned in an overlapping relationship within an existing wellbore casing. In order minimize surge pressures within the borehole during placement of the apparatus 2300, the fluid passage 2380 is preferably provided with one or more pressure relief passages. During the placement of the apparatus 2300 in the wellbore, the casing 2375 is supported by the expansion cone 2355.

After positioning of the apparatus 2300 within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage 2380 from a surface location. The first fluidic material

is conveyed from the fluid passage 2380 to the fluid passages 2385, 2390, 2395, 2405, 2415, and 2485. The first fluidic material will then exit the apparatus 2300 and fill the annular region between the outside of the apparatus 2300 and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, epoxy, drilling mud, slag mix, cement, or water. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, slag mix, epoxy, or cement. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus 2300 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi, and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the apparatus 2300 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus 2300 has been filled to a predetermined level, a plug 2470, dart, or other similar device is introduced into the first fluidic material. The plug 2470 lodges in the throat passage 2465 thereby fluidicly isolating the fluid passage 2405 from the fluid passage 2415.

After placement of the plug 2470 in the throat passage 2465, a second fluidic material is pumped into the fluid passage 2380 in order to pressurize the pressure chamber 2475. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricants. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant.

The second fluidic material may be pumped into the apparatus 2300 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the apparatus 2300 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The pressurization of the pressure chamber 2475 causes the upper sealing head 2335, outer sealing mandrel 2350, and expansion cone 2355 to move in an axial direction. The pressurization of the pressure chamber 2475 also causes the hydraulic slips 2325 to expand in the radial direction and hold the casing 2375 in a substantially stationary position. Furthermore, as the expansion cone 2355 moves in the axial direction, the expansion cone 2355 pulls the mandrel launcher 2480 and drag blocks 2370 along, which sets the mechanical slips 2365 and stops further axial movement of the mandrel launcher 2480 and casing 2375. In this manner, the axial movement of the expansion cone 2355 radially expands the mandrel launcher 2480 and casing 2375.

Once the upper sealing head 2335, outer sealing mandrel 2350, and expansion cone 2355 complete an axial stroke, the operating pressure of the second fluidic material is reduced. The reduction in the operating pressure of the second fluidic material releases the hydraulic slips 2325. The drill string 2305 is then raised. This causes the inner sealing mandrel 2330, lower sealing head 2340, load mandrel 2345, and mechanical slip body 2360 to move upward. This unsets the mechanical slips 2365 and permits the mechanical slips 2365 and drag blocks 2370 to be moved within the mandrel launcher 2480 and casing 2375. When the lower sealing head 2340 contacts the upper sealing head 2335, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher 2480 and casing 2375 are radial expanded through repeated axial strokes of the upper sealing head 2335, outer sealing mandrel 2350 and expansion cone 2355. Throughput

the radial expansion process, the upper end of the casing 2375 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 2375 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the sealing members provided at the upper end of the casing 2375 provide a fluidic seal between the outside surface of the upper end of the casing 2375 and the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the contact pressure between the casing 2375 and the existing section of wellbore casing ranges from about 400 to 10,000 psi in order to optimally provide contact pressure, activate the sealing members, and withstand typical tensile and compressive loading conditions.

In a preferred embodiment, as the expansion cone 2355 nears the upper end of the casing 2375, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus 2300. In an alternative embodiment, the apparatus 2300 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2375.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2355 nears the end of the casing 2375 in order to optimally provide reduced axial movement and velocity of the expansion cone 2355. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2300 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 2355 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 2300 ranges from about 10 to 45 feet in order to optimally provide equipment that can be handled by typical oil well rigging equipment and minimize the frequency at which the expansion cone 2355 must be stopped to permit the apparatus 2300 to be re-stroked.

In an alternative embodiment, at least a portion of the upper sealing head 2335 includes an expansion cone for radially expanding the mandrel launcher 2480 and

casing 2375 during operation of the apparatus 2300 in order to increase the surface area of the casing 2375 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips 2365 are positioned in an axial location between the sealing sleeve 2315 and the inner sealing mandrel 2330 in order to optimally the construction and operation of the apparatus 2300.

Upon the complete radial expansion of the casing 2375, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing 2375 and the interior walls of the wellbore. In the case where the casing 2375 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2375. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus 2300 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2300 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2300 may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 2300 are limited to the fluid passages 2380, 2385, 2390, 2395, 2400, 2405, and 2410, and the pressure chamber 2475. No fluid pressure acts directly on the mandrel launcher 2480 and casing 2375. This permits the use of operating pressures higher than the mandrel launcher 2480 and casing 2375 could normally withstand.

Referring now to Figure 18, a preferred embodiment of an apparatus 2500 for forming a mono-diameter wellbore casing will be described. The apparatus 2500 preferably includes a drillpipe 2505, an innerstring adapter 2510, a sealing sleeve 2515, a hydraulic slip body 2520, hydraulic slips 2525, an inner sealing mandrel 2530, upper sealing head 2535, lower sealing head 2540, outer sealing mandrel 2545, load mandrel 2550, expansion cone 2555, casing 2560, and fluid passages 2565, 2570, 2575, 2580, 2585, 2590, 2595, and 2600.

The drillpipe 2505 is coupled to the innerstring adapter 2510. During operation of the apparatus 2500, the drillpipe 2505 supports the apparatus 2500. The drillpipe 2505 preferably comprises a substantially hollow tubular member or members. The drillpipe 2505 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the drillpipe 2505 is fabricated from coiled tubing in order to faciliate the placement of the apparatus 2500 in non-vertical wellbores. The drillpipe 2505 may be coupled to the innerstring adapter 2510 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2505 is removably coupled to the innerstring adapter 2510 by a drillpipe connection. a drillpipe connection provides the advantages of high strength and easy disassembly.

The drillpipe 2505 preferably includes a fluid passage 2565 that is adapted to convey fluidic materials from a surface location into the fluid passage 2570. In a preferred embodiment, the fluid passage 2565 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 2510 is coupled to the drill string 2505 and the sealing sleeve 2515. The innerstring adapter 2510 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2510 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the innerstring adapter 2510 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 2510 may be coupled to the drill string 2505 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2510 is removably coupled to the drill pipe 2505 by a drillpipe connection. The innerstring adapter 2510 may be coupled to the sealing sleeve 2515 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2510 is removably coupled to the sealing sleeve 2515 by a standard threaded connection.

The innerstring adapter 2510 preferably includes a fluid passage 2570 that is adapted to convey fluidic materials from the fluid passage 2565 into the fluid passage 2575. In a preferred embodiment, the fluid passage 2570 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 2515 is coupled to the innerstring adapter 2510 and the hydraulic slip body 2520. The sealing sleeve 2515 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 2515 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2515 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low-friction surfaces.

The sealing sleeve 2515 may be coupled to the innerstring adapter 2510 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded

connection. In a preferred embodiment, the sealing sleeve 2515 is removably coupled to the innerstring adapter 2510 by a standard threaded connection. The sealing sleeve 2515 may be coupled to the hydraulic slip body 2520 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2515 is removably coupled to the hydraulic slip body 2520 by a standard threaded connection.

The sealing sleeve 2515 preferably includes a fluid passage 2575 that is adapted to convey fluidic materials from the fluid passage 2570 into the fluid passage 2580. In a preferred embodiment, the fluid passage 2575 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slip body 2520 is coupled to the sealing sleeve 2515, the hydraulic slips 2525, and the inner sealing mandrel 2530. The hydraulic slip body 2520 preferably comprises a substantially hollow tubular member or members. The hydraulic slip body 2520 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the hydraulic slip body 2520 is fabricated from carbon steel in order to optimally provide high strength.

The hydraulic slip body 2520 may be coupled to the sealing sleeve 2515 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2520 is removably coupled to the sealing sleeve 2515 by a standard threaded connection. The hydraulic slip body 2520 may be coupled to the slips 2525 using any number of conventional

commercially available mechanical couplings such as, for example, threaded connection or welding. In a preferred embodiment, the hydraulic slip body 2520 is removably coupled to the slips 2525 by a threaded connection. The hydraulic slip body 2520 may be coupled to the inner sealing mandrel 2530 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the hydraulic slip body 2520 is removably coupled to the inner sealing mandrel 2530 by a standard threaded connection.

The hydraulic slips body 2520 preferably includes a fluid passage 2580 that is adapted to convey fluidic materials from the fluid passage 2575 into the fluid passage 2590. In a preferred embodiment, the fluid passage 2580 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The hydraulic slips body 2520 preferably includes fluid passages 2585 that are adapted to convey fluidic materials from the fluid passage 2580 into the pressure chambers of the hydraulic slips 2525. In this manner, the slips 2525 are activated upon the pressurization of the fluid passage 2580 into contact with the inside surface of the casing 2560. In a preferred embodiment, the fluid passages 2585 are adapted to convey fluidic materials such as, for example, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips 2525 are coupled to the outside surface of the hydraulic slip body 2520. During operation of the apparatus 2500, the slips 2525 are activated upon the pressurization of the fluid passage 2580 into contact with the inside surface of the casing 2560. In this manner, the slips 2525 maintain the casing 2560 in a substantially stationary position.

The slips 2525 preferably include the fluid passages 2585, the pressure chambers 2605, spring bias 2610, and slip members 2615. The slips 2525 may comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In a preferred embodiment, the slips 2525 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2560 during the expansion process.

The inner sealing mandrel 2530 is coupled to the hydraulic slip body 2520 and the lower sealing head 2540. The inner sealing mandrel 2530 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 2530 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the inner sealing mandrel 2530 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The inner sealing mandrel 2530 may be coupled to the hydraulic slip body 2520 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2530 is removably coupled to the hydraulic slip body 2520 by a standard threaded connection. The inner sealing mandrel 2530 may be coupled to the lower sealing head 2540 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty type threaded connection, drillpipe connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2530 is removably coupled to the lower sealing head 2540 by a standard threaded connection.

The inner sealing mandrel 2530 preferably includes a fluid passage 2590 that is adapted to convey fluidic materials from the fluid passage 2580 into the fluid passage 2600. In a preferred embodiment, the fluid passage 2590 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The upper sealing head 2535 is coupled to the outer sealing mandrel 2545 and expansion cone 2555. The upper sealing head 2535 is also movably coupled to the outer surface of the inner sealing mandrel 2530 and the inner surface of the casing 2560. In this manner, the upper sealing head 2535 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head 2535 and the outer surface of the inner sealing mandrel 2530 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 2535 and the outer surface of the inner sealing mandrel 2530 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the upper sealing head 2535 and the inner surface of the casing 2560 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 2535 and the inner surface of the casing 2560 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2535 during the expansion process.

The upper sealing head 2535 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 2535 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, ow alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the upper sealing head 2535 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the

upper sealing head 2535 preferably includes one or more annular sealing members 2620 for sealing the interface between the upper sealing head 2535 and the inner sealing mandrel 2530. The sealing members 2620 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2620 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the upper sealing head 2535 includes a shoulder 2625 for supporting the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555 on the lower sealing head 2540.

The upper sealing head 2535 may be coupled to the outer sealing mandrel 2545 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, pipeline connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the upper sealing head 2535 is removably coupled to the outer sealing mandrel 2545 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the upper sealing head 2535 and the outer sealing mandrel 2545 includes one or more sealing members 2630 for fluidicly sealing the interface between the upper sealing head 2535 and the outer sealing mandrel 2545. The sealing members 2630 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2630 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2540 is coupled to the inner sealing mandrel 2530 and the load mandrel 2550. The lower sealing head 2540 is also movably coupled to the inner surface of the outer sealing mandrel 2545. In this manner, the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555 reciprocate in the axial direction.

The radial clearance between the outer surface of the lower sealing head 2540 and the inner surface of the outer sealing mandrel 2545 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the lower sealing head 2540 and the inner surface of the outer sealing mandrel 2545 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The lower sealing head 2540 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 2540 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the lower sealing head 2540 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head 2540 preferably includes one or more annular sealing members 2635 for sealing the interface between the lower sealing head 2540 and the outer sealing mandrel 2545. The sealing members 2635 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2635 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2540 may be coupled to the inner sealing mandrel 2530 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connections, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2540 is removably coupled to the inner sealing mandrel 2530 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2540 and the inner sealing mandrel 2530 includes one or more sealing members 2640 for fluidicly sealing the interface between the lower sealing head 2540 and the inner sealing mandrel 2530. The sealing

members 2640 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2640 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2540 may be coupled to the load mandrel 2550 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the lower sealing head 2540 is removably coupled to the load mandrel 2550 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2540 and the load mandrel 2550 includes one or more sealing members 2645 for fluidicly sealing the interface between the lower sealing head 2540 and the load mandrel 2550. The sealing members 2645 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2645 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the lower sealing head 2540 includes a throat passage 2650 fluidicly coupled between the fluid passages 2590 and 2600. The throat passage 2650 is preferably of reduced size and is adapted to receive and engage with a plug 2655, or other similar device. In this manner, the fluid passage 2590 is fluidicly isolated from the fluid passage 2600. In this manner, the pressure chamber 2660 is pressurized.

The outer sealing mandrel 2545 is coupled to the upper sealing head 2535 and the expansion cone 2555. The outer sealing mandrel 2545 is also movably coupled to the inner surface of the casing 2560 and the outer surface of the lower sealing head 2540. In this manner, the upper sealing head 2535, outer sealing mandrel 2545, and the expansion cone 2555 reciprocate in the axial direction. The radial clearance

between the outer surface of the outer sealing mandrel 2545 and the inner surface of the casing 2560 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the outer sealing mandrel 2545 and the inner surface of the casing 2560 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2535 during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel 2545 and the outer surface of the lower sealing head 2540 may range, for example, from about 0.005 to 0.01 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing mandrel 2545 and the outer surface of the lower sealing head 2540 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The outer sealing mandrel 2545 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel 2545 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the outer sealing mandrel 2545 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel 2545 may be coupled to the upper sealing head 2535 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2545 is removably coupled to the upper sealing head 2535 by a standard threaded connection. The outer sealing mandrel 2545 may be coupled to the expansion cone 2555 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a

preferred embodiment, the outer sealing mandrel 2545 is removably coupled to the expansion cone 2555 by a standard threaded connection.

The upper sealing head 2535, the lower sealing head 2540, the inner sealing mandrel 2530, and the outer sealing mandrel 2545 together define a pressure chamber 2660. The pressure chamber 2660 is fluidicly coupled to the passage 2590 via one or more passages 2595. During operation of the apparatus 2500, the plug 2655 engages with the throat passage 2650 to fluidicly isolate the fluid passage 2590 from the fluid passage 2600. The pressure chamber 2660 is then pressurized which in turn causes the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555 to reciprocate in the axial direction. The axial motion of the expansion cone 2555 in turn expands the casing 2560 in the radial direction.

The load mandrel 2550 is coupled to the lower sealing head 2540. The load mandrel 2550 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 2550 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 2550 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 2550 may be coupled to the lower sealing head 2540 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods, drillpipe connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the load mandrel 2550 is removably coupled to the lower sealing head 2540 by a standard threaded connection.

The load mandrel 2550 preferably includes a fluid passage 2600 that is adapted to convey fluidic materials from the fluid passage 2590 to the region outside of the apparatus 2500. In a preferred embodiment, the fluid passage 2600 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or

lubricants at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 2555 is coupled to the outer sealing mandrel 2545. The expansion cone 2555 is also movably coupled to the inner surface of the casing 2560. In this manner, the upper sealing head 2535, outer sealing mandrel 2545, and the expansion cone 2555 reciprocate in the axial direction. The reciprocation of the expansion cone 2555 causes the casing 2560 to expand in the radial direction.

The expansion cone 2555 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 in order to optimally provide radial expansion for the widest variety of tubular casings. The axial length of the expansion cone 2555 may range, for example, from about 2 to 8 times the largest outside diameter of the expansion cone 2535. In a preferred embodiment, the axial length of the expansion cone 2535 ranges from about 3 to 5 times the largest outside diameter of the expansion cone 2535 in order to optimally provide stabilization and centralization of the expansion cone 2535 during the expansion process. In a particularly preferred embodiment, the maximum outside diameter of the expansion cone 2555 is between about 95 to 99 % of the inside diameter of the existing wellbore that the casing 2560 will be joined with. In a preferred embodiment, the angle of attack of the expansion cone 2555 ranges from about 5 to 30 degrees in order to optimally balance frictional forces and radial expansion forces. The optimum angle of attack of the expansion cone 2535 will vary as a function of the particular operational features of the expansion operation.

The expansion cone 2555 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In a preferred embodiment, the expansion cone 2555 is fabricated from D2 machine tool steel in order to optimally provide high strength, and resistance to wear and

galling. In a particularly preferred embodiment, the outside surface of the expansion cone 2555 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and wear resistance.

The expansion cone 2555 may be coupled to the outside sealing mandrel 2545 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the expansion cone 2555 is coupled to the outside sealing mandrel 2545 using a standard threaded connection in order to optimally provide high strength and easy replacement of the expansion cone 2555.

The casing 2560 is removably coupled to the slips 2525 and expansion cone 2555. The casing 2560 preferably comprises a tubular member. The casing 2560 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 2560 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength using standardized materials.

In a preferred embodiment, the upper end 2665 of the casing 2560 includes a thin wall section 2670 and an outer annular sealing member 2675. In a preferred embodiment, the wall thickness of the thin wall section 2670 is about 50 to 100 % of the regular wall thickness of the casing 2560. In this manner, the upper end 2665 of the casing 2560 may be easily radially expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. In a preferred embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section 2670 of casing 2560 into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member 2675 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal, or plastic. In a preferred embodiment, the annular sealing member 2675 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular sealing member 2675 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the wellbore casing that the casing 2560 is joined to. In this manner, after radial expansion, the annular sealing member 2670 optimally provides a fluidic seal and also preferably optimally provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing 2560 to support the casing 2560.

In a preferred embodiment, the lower end 2680 of the casing 2560 includes a thin wall section 2685 and an outer annular sealing member 2690. In a preferred embodiment, the wall thickness of the thin wall section 2685 is about 50 to 100 % of the regular wall thickness of the casing 2560. In this manner, the lower end 2680 of the casing 2560 may be easily expanded and deformed. Furthermore, in this manner, an other section of casing may be easily joined with the lower end 2680 of the casing 2560 using a radial expansion process. In a preferred embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section 2685 of the lower end 2680 of the casing 2560 results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member 2690 may be fabricated from any number of conventional commercially available sealing materials such as, for example, rubber, metal, plastic or epoxy. In a preferred embodiment, the annular sealing member 2690 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular sealing member 2690 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 2560 is joined to. In this

manner, after radial expansion, the annular sealing member 2690 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 2560 to support the casing 2560.

During operation, the apparatus 2500 is preferably positioned in a wellbore with the upper end 2665 of the casing 2560 positioned in an overlapping relationship with the lower end of an existing wellbore casing. In a particularly preferred embodiment, the thin wall section 2670 of the casing 2560 is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing 2560 will compress the thin wall sections and annular compressible members of the upper end 2665 of the casing 2560 and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus 2500 in the wellbore, the casing 2560 is supported by the expansion cone 2555.

After positioning of the apparatus 2500, a first fluidic material is then pumped into the fluid passage 2565. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, cement, water, slag-mix, epoxy or drilling mud. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement, epoxy, or slag-mix in order to optimally provide a hardenable outer annular body around the expanded casing 2560.

The first fluidic material may be pumped into the fluid passage 2565 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the fluid passage 2565 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The first fluidic material pumped into the fluid passage 2565 passes through the fluid passages 2570, 2575, 2580, 2590, 2600 and then outside of the apparatus 2500. The first fluidic material then preferably fills the annular region between the outside of the apparatus 2500 and the interior walls of the wellbore.

The plug 2655 is then introduced into the fluid passage 2565. The plug 2655 lodges in the throat passage 2650 and fluidicly isolates and blocks off the fluid passage 2590. In a preferred embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 2565 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage 2565. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud, or lubricant in order to optimally provide pressurization of the pressure chamber 2660 and minimize friction.

The second fluidic material may be pumped into the fluid passage 2565 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the fluid passage 2565 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage 2565 passes through the fluid passages 2570, 2575, 2580, 2590 and into the pressure chambers 2605 of the slips 2525, and into the pressure chamber 2660. Continued pumping of the second fluidic material pressurizes the pressure chambers 2605 and 2660.

The pressurization of the pressure chambers 2605 causes the slip members 2525 to expand in the radial direction and grip the interior surface of the casing 2560. The casing 2560 is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chamber 2660 causes the upper sealing head 2535, outer sealing mandrel 2545 and expansion cone 2555 to move in an axial direction relative to the casing 2560. In this manner, the expansion cone 2555 will cause the casing 2560 to expand in the radial direction, beginning with the lower end 2685 of the casing 2560.

During the radial expansion process, the casing 2560 is prevented from moving in an upward direction by the slips 2525. A length of the casing 2560 is then expanded in the radial direction through the pressurization of the pressure chamber 2660. The length of the casing 2560 that is expanded during the expansion process will be proportional to the stroke length of the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the upper sealing head 2535, outer sealing mandrel 2545, and expansion cone 2555 drop to their rest positions with the casing 2560 supported by the expansion cone 2555. The position of the drillpipe 2505 is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 2560. In a preferred embodiment, the stroking of the expansion cone 2555 is then repeated, as necessary, until the thin walled section 2670 of the upper end 2665 of the casing 2560 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

In a preferred embodiment, during the final stroke of the expansion cone 2555, the slips 2525 are positioned as close as possible to the thin walled section 2670 of the upper end 2665 of the casing 2560 in order minimize slippage between the casing 2560 and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the annular sealing member 2675 is selected to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing 2560 during the final stroke. Alternatively, or in addition, the outside diameter of the annular sealing member 2690 is selected to provide an interference fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing 2560. In this final alternative, the interference fit is preferably selected to permit expansion of the casing 2560 by pulling the expansion cone 2555 out of the wellbore, without having to pressurize the pressure chamber 2660.

During the radial expansion process, the pressurized areas of the apparatus 2500 are preferably limited to the fluid passages 2565, 2570, 2575, 2580, and 2590, the pressure chambers 2605 within the slips 2525, and the pressure chamber 2660. No fluid pressure acts directly on the casing 2560. This permits the use of operating pressures higher than the casing 2560 could normally withstand.

Once the casing 2560 has been completely expanded off of the expansion cone 2555, the remaining portions of the apparatus 2500 are removed from the wellbore. In a preferred embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end 2665 of the casing 2560 ranges from about 400 to 10,000 psi in order to optimally support the casing 2560 using the existing wellbore casing.

In this manner, the casing 2560 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 2565, 2570, 2575, 2580, and 2590, the pressure chambers of the slips 2605 and the pressure chamber 2660 of the apparatus 2500.

In a preferred embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing 2560. In the case where the casing 2560 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2560. The resulting new section of wellbore casing includes the expanded casing 2560 and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 2560 includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, á mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In a preferred embodiment, as the expansion cone 2555 nears the upper end 2665 of the casing 2560, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus 2500. In an alternative embodiment, the apparatus 2500 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2560.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2555 nears the end of the casing 2560 in order to optimally provide reduced axial movement and velocity of the expansion cone 2555. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2500 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 2555 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 2500 ranges from about 10 to 45 feet in order to optimally provide equipments lengths that can be easily handled using typical oil well rigging equipment and also minimize the frequency at which apparatus 2500 must be re-stroked.

In an alternative embodiment, at least a portion of the upper sealing head 2535 includes an expansion cone for radially expanding the casing 2560 during operation of the apparatus 2500 in order to increase the surface area of the casing 2560 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Alternatively, the apparatus 2500 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2500 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2500 may be used to expand a tubular support member in a hole.

Referring now to Figures 19, 19a and 19b, another embodiment of an apparatus 2700 for expanding a tubular member will be described. The apparatus 2700 preferably includes a drillpipe 2705, an innerstring adapter 2710, a sealing sleeve 2715, a first inner sealing mandrel 2720, a first upper sealing head 2725, a first lower sealing head 2730, a first outer sealing mandrel 2735, a second inner sealing mandrel 2740, a second upper sealing head 2745, a second lower sealing head 2750, a second outer sealing mandrel 2755, a load mandrel 2760, an expansion cone 2765, a mandrel launcher 2770, a mechanical slip body 2775, mechanical slips 2780, drag blocks 2785, casing 2790, and fluid passages 2795, 2800, 2805, 2810, 2815, 2820, 2825, and 2830.

The drillpipe 2705 is coupled to the innerstring adapter 2710. During operation of the apparatus 2700, the drillpipe 2705 supports the apparatus 2700. The drillpipe 2705 preferably comprises a substantially hollow tubular member or members. The drillpipe 2705 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the drillpipe 2705 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 2700 in non-vertical wellbores. The drillpipe 2705 may be coupled to the innerstring adapter 2710 using any number of

conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2705 is removably coupled to the innerstring adapter 2710 by a drillpipe connection in order to optimally provide high strength and easy disassembly.

The drillpipe 2705 preferably includes a fluid passage 2795 that is adapted to convey fluidic materials from a surface location into the fluid passage 2800. In a preferred embodiment, the fluid passage 2795 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 2710 is coupled to the drill string 2705 and the sealing sleeve 2715. The innerstring adapter 2710 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2710 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the innerstring adapter 2710 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 2710 may be coupled to the drill string 2705 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2710 is removably coupled to the drill pipe 2705 by a standard threaded connection in order to optimally provide high strength and easy disassembly. The innerstring adapter 2710 may be coupled to the sealing sleeve 2715 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded

connection. In a preferred embodiment, the innerstring adapter 2710 is removably coupled to the sealing sleeve 2715 by a standard threaded connection.

The innerstring adapter 2710 preferably includes a fluid passage 2800 that is adapted to convey fluidic materials from the fluid passage 2795 into the fluid passage 2805. In a preferred embodiment, the fluid passage 2800 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 2715 is coupled to the innerstring adapter 2710 and the first inner sealing mandrel 2720. The sealing sleeve 2715 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 2715 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2715 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The sealing sleeve 2715 may be coupled to the innerstring adapter 2710 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2715 is removably coupled to the innerstring adapter 2710 by a standard threaded connector. The sealing sleeve 2715 may be coupled to the first inner sealing mandrel 2720 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2715 is removably coupled to the inner sealing mandrel 2720 by a standard threaded connection.

The sealing sleeve 2715 preferably includes a fluid passage 2802 that is adapted to convey fluidic materials from the fluid passage 2800 into the fluid passage 2805. In a preferred embodiment, the fluid passage 2802 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 2720 is coupled to the sealing sleeve 2715 and the first lower sealing head 2730. The first inner sealing mandrel 2720 preferably comprises a substantially hollow tubular member or members. The first inner sealing mandrel 2720 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first inner sealing mandrel 2720 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first inner sealing mandrel 2720 may be coupled to the sealing sleeve 2715 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 2720 is removably coupled to the sealing sleeve 2715 by a standard threaded connection. The first inner sealing mandrel 2720 may be coupled to the first lower sealing head 2730 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 2720 is removably coupled to the first lower sealing head 2730 by a standard threaded connection.

The first inner sealing mandrel 2720 preferably includes a fluid passage 2805 that is adapted to convey fluidic materials from the fluid passage 2802 into the fluid

passage 2810. In a preferred embodiment, the fluid passage 2805 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first upper sealing head 2725 is coupled to the first outer sealing mandrel 2735, the second upper sealing head 2745, the second outer sealing mandrel 2755, and the expansion cone 2765. The first upper sealing head 2725 is also movably coupled to the outer surface of the first inner sealing mandrel 2720 and the inner surface of the casing 2790. In this manner, the first upper sealing head 2725 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the first upper sealing head 2725 and the outer surface of the first inner sealing mandrel 2720 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the first upper sealing head 2725 and the outer surface of the first inner sealing mandrel 2720 ranges from about 0.005 to 0.125 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the first upper sealing head 2725 and the inner surface of the casing 2790 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the first upper sealing head 2725 and the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process.

The first upper sealing head 2725 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first upper sealing head 2725 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first upper sealing head 2725 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance and low friction

surfaces. The inner surface of the first upper sealing head 2725 preferably includes one or more annular sealing members 2835 for sealing the interface between the first upper sealing head 2725 and the first inner sealing mandrel 2720. The sealing members 2835 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2835 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In a preferred embodiment, the first upper sealing head 2725 includes a shoulder 2840 for supporting the first upper sealing head 2725 on the first lower sealing head 2730.

The first upper sealing head 2725 may be coupled to the first outer sealing mandrel 2735 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the first upper sealing head 2725 is removably coupled to the first outer sealing mandrel 2735 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first upper sealing head 2725 and the first outer sealing mandrel 2735 includes one or more sealing members 2845 for fluidicly sealing the interface between the first upper sealing head 2725 and the first outer sealing mandrel 2735. The sealing members 2845 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2845 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 is coupled to the first inner sealing mandrel 2720 and the second inner sealing mandrel 2740. The first lower sealing head 2730 is also movably coupled to the inner surface of the first outer sealing mandrel 2735.

In this manner, the first upper sealing head 2725 and first outer sealing mandrel 2735 reciprocate in the axial direction. The radial clearance between the outer surface of the first lower sealing head 2730 and the inner surface of the first outer sealing mandrel 2735 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the first lower sealing head 2730 and the inner surface of the first outer sealing mandrel 2735 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first lower sealing head 2730 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first lower sealing head 2730 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first lower sealing head 2730 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the first lower sealing head 2730 preferably includes one or more annular sealing members 2850 for sealing the interface between the first lower sealing head 2730 and the first outer sealing mandrel 2735. The sealing members 2850 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2850 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 may be coupled to the first inner sealing mandrel 2720 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connections, welding, amorphous bonding, or standard threaded connection. In a preferred embodiment, the first lower sealing head 2730 is removably coupled to the first inner sealing mandrel 2720 by a standard threaded connection. In a preferred

embodiment, the mechanical coupling between the first lower sealing head 2730 and the first inner sealing mandrel 2720 includes one or more sealing members 2855 for fluidicly sealing the interface between the first lower sealing head 2730 and the first inner sealing mandrel 2720. The sealing members 2855 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2855 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first lower sealing head 2730 may be coupled to the second inner sealing mandrel 2740 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2730 is removably coupled to the second inner sealing mandrel 2740 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first lower sealing head 2730 and the second inner sealing mandrel 2740 includes one or more sealing members 2860 for fluidicly sealing the interface between the first lower sealing head 2730 and the second inner sealing mandrel 2740. The sealing members 2860 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2860 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The first outer sealing mandrel 2735 is coupled to the first upper sealing head 2725, the second upper sealing head 2745, the second outer sealing mandrel 2755, and the expansion cone 2765. The first outer sealing mandrel 2735 is also movably coupled to the inner surface of the casing 2790 and the outer surface of the first lower sealing head 2730. In this manner, the first upper sealing head 2725, first outer sealing mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The radial

clearance between the outer surface of the first outer sealing mandrel 2735 and the inner surface of the casing 2790 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the first outer sealing mandrel 2735 and the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process. The radial clearance between the inner surface of the first outer sealing mandrel 2735 and the outer surface of the first lower sealing head 2730 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner surface of the first outer sealing mandrel 2735 and the outer surface of the first lower sealing head 2730 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The outer sealing mandrel 1935 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first outer sealing mandrel 2735 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first outer sealing mandrel 2735 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first outer sealing mandrel 2735 may be coupled to the first upper sealing head 2725 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 2735 is removably coupled to the first upper sealing head 2725 by a standard threaded connection. The first outer sealing mandrel 2735 may be coupled to the second upper sealing head 2745 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a

standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 2735 is removably coupled to the second upper sealing head 2745 by a standard threaded connection.

The second inner sealing mandrel 2740 is coupled to the first lower sealing head 2730 and the second lower sealing head 2750. The second inner sealing mandrel 2740 preferably comprises a substantially hollow tubular member or members. The second inner sealing mandrel 2740 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second inner sealing mandrel 2740 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second inner sealing mandrel 2740 may be coupled to the first lower sealing head 2730 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 2740 is removably coupled to the first lower sealing head 2740 by a standard threaded connection. The mechanical coupling between the second inner sealing mandrel 2740 and the first lower sealing head 2730 preferably includes sealing members 2860.

The second inner sealing mandrel 2740 may be coupled to the second lower sealing head 2750 using any number of conventional commercially available mechanical couplings such as, for example, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 2720 is removably coupled to the second lower sealing head 2750 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second inner sealing mandrel 2740 and the second lower sealing head 2750 includes one or more sealing members 2865. The sealing members 2865 may comprise any number

of conventional commercially available seals such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2865 comprise polypak seals available from Parker Seals.

The second inner sealing mandrel 2740 preferably includes a fluid passage 2810 that is adapted to convey fluidic materials from the fluid passage 2805 into the fluid passage 2815. In a preferred embodiment, the fluid passage 2810 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The second upper sealing head 2745 is coupled to the first upper sealing head 2725, the first outer sealing mandrel 2735, the second outer sealing mandrel 2755, and the expansion cone 2765. The second upper sealing head 2745 is also movably coupled to the outer surface of the second inner sealing mandrel 2740 and the inner surface of the casing 2790. In this manner, the second upper sealing head 2745 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the second upper sealing head 2745 and the outer surface of the second inner sealing mandrel 2740 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the second upper sealing head 2745 and the outer surface of the second inner sealing mandrel 2740 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the second upper sealing head 2745 and the inner surface of the casing 2790 may range, for example, from about 0.025 to .375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the second upper sealing head 2745 and the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process.

The second upper sealing head 2745 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second upper sealing

head 2745 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second upper sealing head 2745 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the second upper sealing head 2745 preferably includes one or more annular sealing members 2870 for sealing the interface between the second upper sealing head 2745 and the second inner sealing mandrel 2740. The sealing members 2870 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2870 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In a preferred embodiment, the second upper sealing head 2745 includes a shoulder 2875 for supporting the second upper sealing head 2745 on the second lower sealing head 2750.

The second upper sealing head 2745 may be coupled to the first outer sealing mandrel 2735 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 2745 is removably coupled to the first outer sealing mandrel 2735 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second upper sealing head 2745 and the first outer sealing mandrel 2735 includes one or more sealing members 2880 for fluidicly sealing the interface between the second upper sealing head 2745 and the first outer sealing mandrel 2735. The sealing members 2880 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2880 comprise

polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second upper sealing head 2745 may be coupled to the second outer sealing mandrel 2755 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 2745 is removably coupled to the second outer sealing mandrel 2755 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second upper sealing head 2745 and the second outer sealing mandrel 2755 includes one or more sealing members 2885 for fluidicly sealing the interface between the second upper sealing head 2745 and the second outer sealing mandrel 2755. The sealing members 2885 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2885 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 2750 is coupled to the second inner sealing mandrel 2740 and the load mandrel 2760. The second lower sealing head 2750 is also movably coupled to the inner surface of the second outer sealing mandrel 2755. In this manner, the first upper sealing head 2725, the first outer sealing mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The radial clearance between the outer surface of the second lower sealing head 2750 and the inner surface of the second outer sealing mandrel 2755 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the second lower sealing head 2750 and the inner surface of the second outer sealing mandrel 2755 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second lower sealing head 2750 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second lower sealing head 2750 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second lower sealing head 2750 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the second lower sealing head 2750 preferably includes one or more annular sealing members 2890 for sealing the interface between the second lower sealing head 2750 and the second outer sealing mandrel 2755. The sealing members 2890 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2890 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 2750 may be coupled to the second inner sealing mandrel 2740 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 2750 is removably coupled to the second inner sealing mandrel 2740 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second lower sealing head 2750 and the second inner sealing mandrel 2740 includes one or more sealing members 2895 for fluidicly sealing the interface between the second sealing head 2750and the second sealing mandrel 2740. The sealing members 2895 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2895 comprise

polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second lower sealing head 2750 may be coupled to the load mandrel 2760 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield tubular goods specialty threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 2750 is removably coupled to the load mandrel 2760 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second lower sealing head 2750 and the load mandrel 2760 includes one or more sealing members 2900 for fluidicly sealing the interface between the second lower sealing head 2750 and the load mandrel 2760. The sealing members 2900 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2900 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

In a preferred embodiment, the second lower sealing head 2750 includes a throat passage 2905 fluidicly coupled between the fluid passages 2810 and 2815. The throat passage 2905 is preferably of reduced size and is adapted to receive and engage with a plug 2910, or other similar device. In this manner, the fluid passage 2810 is fluidicly isolated from the fluid passage 2815. In this manner, the pressure chambers 2915 and 2920 are pressurized. The use of a plurality of pressure chambers in the apparatus 2700 permits the effective driving force to be multiplied. While illustrated using a pair of pressure chambers, 2915 and 2920, the apparatus 2700 may be further modified to employ additional pressure chambers.

The second outer sealing mandrel 2755 is coupled to the first upper sealing head 2725, the first outer sealing mandrel 2735, the second upper sealing head 2745, and the expansion cone 2765. The second outer sealing mandrel 2755 is also movably coupled to the inner surface of the casing 2790 and the outer surface of the second

lower sealing head 2750. In this manner, the first upper sealing head 2725, first outer sealing mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction.

The radial clearance between the outer surface of the second outer sealing mandrel 2755 and the inner surface of the casing 2790 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the second outer sealing mandrel 2755 and the inner surface of the casing 2790 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2765 during the expansion process. The radial clearance between the inner surface of the second outer sealing mandrel 2755 and the outer surface of the second lower sealing head 2750 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner surface of the second outer sealing mandrel 2755 and the outer surface of the second lower sealing head 2750 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second outer sealing mandrel 2755 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second outer sealing mandrel 2755 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second outer sealing mandrel 2755 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second outer sealing mandrel 2755 may be coupled to the second upper sealing head 2745 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the second outer sealing mandrel 2755 is removably coupled to the second upper sealing head 2745 by

The casing 3335 may be expanded in the radial direction using any number of conventional commercially available methods. The casing 3335 is expanded in the radial direction using one or more of the processes and apparatus described within the present disclosure.

The seals 3340 prevent the passage of fluids and other materials within the annular region 3365 between the solid casings 3335 and 3350 and the wellbore 3305. The seals 3340 may comprise any number of conventional commercially available sealing materials suitable for sealing a casing in a wellbore such as, for example, lead, rubber or epoxy. The seals 3340 comprise Stratalok epoxy material available from Halliburton Energy Services.

The slotted casing 3345 permits fluids and other materials to pass into and out of the interior of the slotted casing 3345 from and to the annular region 3365. In this manner, oil and gas may be produced from a producing subterranean zone within a subterranean formation. The slotted casing 3345 may comprise any number of conventional commercially available sections of slotted tubular casing. The slotted casing 3345 comprises expandable slotted tubular casing available from Petroline in Aberdeen, Scotland. The slotted casing 145 comprises expandable slotted sandscreen tubular casing available from Petroline in Aberdeen, Scotland.

The slotted casing 3345 is preferably coupled to one or more solid casing 3335. The slotted casing 3345 may be coupled to the solid casing 3335 using any number of conventional commercially available processes such as, for example, welding, or slotted or solid expandable connectors. The slotted casing 3345 is coupled to the solid casing 3335 by expandable solid connectors.

The slotted casing 3345 is preferably coupled to one or more intermediate solid casings 3350. The slotted casing 3345 may be coupled to the intermediate solid casing 3350 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. The slotted casing 3345 is coupled to the intermediate solid casing 3350 by expandable solid connectors.

The last section of slotted casing 3345 is preferably coupled to the shoe 3355. The last slotted casing 3345 may be coupled to the shoe 3355 using any number of conventional commercially available processes such as, for example, welding or

a standard threaded connection. The second outer sealing mandrel 2755 may be coupled to the expansion cone 2765 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second outer sealing mandrel 2755 is removably coupled to the expansion cone 2765 by a standard threaded connection.

The load mandrel 2760 is coupled to the second lower sealing head 2750 and the mechanical slip body 2755. The load mandrel 2760 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 2760 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 2760 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 2760 may be coupled to the second lower sealing head 2750 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the load mandrel 2760 is removably coupled to the second lower sealing head 2750 by a standard threaded connection. The load mandrel 2760 may be coupled to the mechanical slip body 2775 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the load mandrel 2760 is removably coupled to the mechanical slip body 2775 by a standard threaded connection.

The load mandrel 2760 preferably includes a fluid passage 2815 that is adapted to convey fluidic materials from the fluid passage 2810 to the fluid passage 2820. In a preferred embodiment, the fluid passage 2815 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 2765 is coupled to the second outer sealing mandrel 2755. The expansion cone 2765 is also movably coupled to the inner surface of the casing 2790. In this manner, the first upper sealing head 2725, first outer sealing mandrel 2735, second upper sealing head 2745, second outer sealing mandrel 2755, and the expansion cone 2765 reciprocate in the axial direction. The reciprocation of the expansion cone 2765 causes the casing 2790 to expand in the radial direction.

The expansion cone 2765 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide expansion cone dimensions that accommodate the typical range of casings. The axial length of the expansion cone 2765 may range, for example, from about 2 to 8 times the largest outer diameter of the expansion cone 2765. In a preferred embodiment, the axial length of the expansion cone 2765 ranges from about 3 to 5 times the largest outer diameter of the expansion cone 2765 in order to optimally provide stabilization and centralization of the expansion cone 2765. In a preferred embodiment, the angle of attack of the expansion cone 2765 ranges from about 5 to 30 degrees in order to optimally balance frictional forces and radial expansion forces.

The expansion cone 2765 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics or other similar high strength materials. In a preferred embodiment, the expansion cone 2765 is fabricated from D2 machine

tool steel in order to optimally provide high strength and resistance to corrosion and galling. In a particularly preferred embodiment, the outside surface of the expansion cone 2765 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resistance to wear and galling.

The expansion cone 2765 may be coupled to the second outside sealing mandrel 2765 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the expansion cone 2765 is coupled to the second outside sealing mandrel 2765 using a standard threaded connection in order to optimally provide high strength and easy replacement of the expansion cone 2765.

The mandrel launcher 2770 is coupled to the casing 2790. The mandrel launcher 2770 comprises a tubular section of casing having a reduced wall thickness compared to the casing 2790. In a preferred embodiment, the wall thickness of the mandrel launcher 2770 is about 50 to 100 % of the wall thickness of the casing 2790. The wall thickness of the mandrel launcher 2770 may range , for example, from about 0.15 to 1.5 inches. In a preferred embodiment, the wall thickness of the mandrel launcher 2770 ranges from about 0.25 to 0.75 inches. In this manner, the initiation of the radial expansion of the casing 2790 is facilitated, the placement of the apparatus 2700 within a wellbore casing and wellbore is facilitated, and the mandrel launcher 2770 has a burst strength approximately equal to that of the casing 2790.

The mandrel launcher 2770 may be coupled to the casing 2790 using any number of conventional mechanical couplings such as, for example, a standard threaded connection. The mandrel launcher 2770 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the mandrel launcher

2770 is fabricated from oilfield country tubular goods of higher strength than that of the casing 2790 but with a reduced wall thickness in order to optimally provide a small compact tubular container having a burst strength approximately equal to that of the casing 2790.

The mechanical slip body 2775 is coupled to the load mandrel 2760, the mechanical slips 2780, and the drag blocks 2785. The mechanical slip body 2775 preferably comprises a tubular member having an inner passage 2820 fluidicly coupled to the passage 2815. In this manner, fluidic materials may be conveyed from the passage 2820 to a region outside of the apparatus 2700.

The mechanical slip body 2775 may be coupled to the load mandrel 2760 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2775 is removably coupled to the load mandrel 2760 using a standard threaded connection in order to optimally provide high strength and easy disassembly. The mechanical slip body 2775 may be coupled to the mechanical slips 2780 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2755 is removably coupled to the mechanical slips 2780 using threaded connections and sliding steel retainer rings in order to optimally provide a high strength attachment. The mechanical slip body 2755 may be coupled to the drag blocks 2785 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 2775 is removably coupled to the drag blocks 2785 using threaded connections and sliding steel retainer rings in order to optimally provide a high strength attachment.

The mechanical slip body 2775 preferably includes a fluid passage 2820 that is adapted to convey fluidic materials from the fluid passage 2815 to the region outside of the apparatus 2700. In a preferred embodiment, the fluid passage 2820 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The mechanical slips 2780 are coupled to the outside surface of the mechanical slip body 2775. During operation of the apparatus 2700, the mechanical slips 2780 prevent upward movement of the casing 2790 and mandrel launcher 2770. In this manner, during the axial reciprocation of the expansion cone 2765, the casing 2790 and mandrel launcher 2770 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2765 and casing 2790 and mandrel launcher 2770 are expanded in the radial direction by the axial movement of the expansion cone 2765.

The mechanical slips 2780 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the mechanical slips 2780 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2790 and mandrel launcher 2770 during the expansion process.

The drag blocks 2785 are coupled to the outside surface of the mechanical slip body 2775. During operation of the apparatus 2700, the drag blocks 2785 prevent upward movement of the casing 2790 and mandrel launcher 2770. In this manner, during the axial reciprocation of the expansion cone 2765, the casing 2790 and mandrel launcher 2770 are maintained in a substantially stationary position. In this manner, the mandrel launcher 2770 and casing 2790 are expanded in the radial direction by the axial movement of the expansion cone 2765.

The drag blocks 2785 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer mechanical drag blocks or Model 3L retrievable bridge plug drag blocks. In a preferred embodiment, the drag blocks 2785 comprise RTTS packer mechanical drag blocks available from Halliburton Energy Services in order to optimally provide resistance to axial

movement of the casing 2790 and mandrel launcher 2770 during the expansion process.

The casing 2790 is coupled to the mandrel launcher 2770. The casing 2790 is further removably coupled to the mechanical slips 2780 and drag blocks 2785. The casing 2790 preferably comprises a tubular member. The casing 2790 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 2790 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength using standardized materials. In a preferred embodiment, the upper end of the casing 2790 includes one or more sealing members positioned about the exterior of the casing 2790.

During operation, the apparatus 2700 is positioned in a wellbore with the upper end of the casing 2790 positioned in an overlapping relationship within an existing wellbore casing. In order minimize surge pressures within the borehole during placement of the apparatus 2700, the fluid passage 2795 is preferably provided with one or more pressure relief passages. During the placement of the apparatus 2700 in the wellbore, the casing 2790 is supported by the expansion cone 2765.

After positioning of the apparatus 2700 within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage 2795 from a surface location. The first fluidic material is conveyed from the fluid passage 2795 to the fluid passages 2800, 2802, 2805, 2810, 2815, and 2820. The first fluidic material will then exit the apparatus 2700 and fill the annular region between the outside of the apparatus 2700 and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, epoxy, drilling mud, slag mix, water or cement. In a preferred embodiment, the first fluidic material comprises a

hardenable fluidic sealing material such as, for example, slag mix, epoxy, or cement. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be formed.

The first fluidic material may be pumped into the apparatus 2700 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the apparatus 2700 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus 2700 has been filled to a predetermined level, a plug 2910, dart, or other similar device is introduced into the first fluidic material. The plug 2910 lodges in the throat passage 2905 thereby fluidicly isolating the fluid passage 2810 from the fluid passage 2815.

After placement of the plug 2910 in the throat passage 2905, a second fluidic material is pumped into the fluid passage 2795 in order to pressurize the pressure chambers 2915 and 2920. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricants. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant. The use of lubricant optimally provides lubrication of the moving parts of the apparatus 2700.

The second fluidic material may be pumped into the apparatus 2700 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the apparatus 2700 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The pressurization of the pressure chambers 2915 and 2920 cause the upper sealing heads, 2725 and 2745, outer sealing mandrels, 2735 and 2755, and expansion cone 2765 to move in an axial direction. As the expansion cone 2765 moves in the axial direction, the expansion cone 2765 pulls the mandrel launcher 2770, casing 2790, and drag blocks 2785 along, which sets the mechanical slips 2780 and stops further axial movement of the mandrel launcher 2770 and casing 2790. In this manner, the axial movement of the expansion cone 2765 radially expands the mandrel launcher 2770 and casing 2790.

Once the upper sealing heads, 2725 and 2745, outer sealing mandrels, 2735 and 2755, and expansion cone 2765 complete an axial stroke, the operating pressure of the second fluidic material is reduced and the drill string 2705 is raised. This causes the inner sealing mandrels, 2720 and 2740, lower sealing heads, 2730 and 2750, load mandrel 2760, and mechanical slip body 2755 to move upward. This unsets the mechanical slips 2780 and permits the mechanical slips 2780 and drag blocks 2785 to be moved upward within the mandrel launcher 2770 and casing 2790. When the lower sealing heads, 2730 and 2750, contact the upper sealing heads, 2725 and 2745, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher 2770 and casing 2790 are radially expanded through repeated axial strokes of the upper sealing heads, 2725 and 2745, outer sealing mandrels, 2735 and 2755, and expansion cone 2765. Throughout the radial expansion process, the upper end of the casing 2790 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 2790 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the sealing members provided at the upper end of the casing 2790 provide a fluidic seal between the outside surface of the upper end of the casing 2790 and the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the contact pressure between the casing 2790 and the existing section of wellbore casing ranges from about 400 to 10,000 in

order to optimally provide contact pressure for activating the sealing members, provide optimal resistance to axial movement of the expanded casing, and optimally resist typical tensile and compressive loads on the expanded casing.

In a preferred embodiment, as the expansion cone 2765 nears the end of the casing 2790, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus 2700. In an alternative embodiment, the apparatus 2700 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2790.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2765 nears the end of the casing 2790 in order to optimally provide reduced axial movement and velocity of the expansion cone 2765. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2700 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 2765 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 2700 ranges from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and minimize the frequency at which the apparatus 2700 must be re-stroked during an expansion operation.

In an alternative embodiment, at least a portion of the upper sealing heads, 2725 and 2745, include expansion cones for radially expanding the mandrel launcher 2770 and casing 2790 during operation of the apparatus 2700 in order to increase the surface area of the casing 2790 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips are positioned in an axial location between the sealing sleeve 1915 and the first inner sealing mandrel 2720 in order to optimally provide a simplified assembly and operation of the apparatus 2700.

Upon the complete radial expansion of the casing 2790, if applicable, the first fluidic material is permitted to cure within the annular region between the outside

of the expanded casing 2790 and the interior walls of the wellbore. In the case where the casing 2790 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2790. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus 2700 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2700 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2700 may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 2700 are limited to the fluid passages 2795, 2800, 2802, 2805, and 2810, and the pressure chambers 2915 and 2920. No fluid pressure acts directly on the mandrel launcher 2770 and casing 2790. This permits the use of operating pressures higher than the mandrel launcher 2770 and casing 2790 could normally withstand.

Referring now to Figure 20, a preferred embodiment of an apparatus 3000 for forming a mono-diameter wellbore casing will be described. The apparatus 3000 preferably includes a drillpipe 3005, an innerstring adapter 3010, a sealing sleeve 3015, a first inner sealing mandrel 3020, hydraulic slips 3025, a first upper sealing head 3030, a first lower sealing head 3035, a first outer sealing mandrel 3040, a second inner sealing mandrel 3045, a second upper sealing head 3050, a second lower sealing head 3055, a second outer sealing mandrel 3060, load mandrel 3065, expansion cone 3070, casing 3075, and fluid passages 3080, 3085, 3090, 3095, 3100, 3105, 3110, 3115 and 3120.

The drillpipe 3005 is coupled to the innerstring adapter 3010. During operation of the apparatus 3000, the drillpipe 3005 supports the apparatus 3000. The drillpipe 3005 preferably comprises a substantially hollow tubular member or members. The drillpipe 3005 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the drillpipe 3005 is fabricated from coiled tubing in

order to faciliate the placement of the apparatus 3000 in non-vertical wellbores. The drillpipe 3005 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 3005 is removably coupled to the innerstring adapter 3010 by a drillpipe connection.

The drillpipe 3005 preferably includes a fluid passage 3080 that is adapted to convey fluidic materials from a surface location into the fluid passage 3085. In a preferred embodiment, the fluid passage 3080 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 3010 is coupled to the drill string 3005 and the sealing sleeve 3015. The innerstring adapter 3010 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 3010 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the innerstring adapter 3010 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 3010 may be coupled to the drill string 3005 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 3010 is removably coupled to the drill pipe 3005 by a drillpipe connection. The innerstring adapter 3010 may be coupled to the sealing sleeve 3015 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded

connection. In a preferred embodiment, the innerstring adapter 3010 is removably coupled to the sealing sleeve 3015 by a standard threaded connection.

The innerstring adapter 3010 preferably includes a fluid passage 3085 that is adapted to convey fluidic materials from the fluid passage 3080 into the fluid passage 3090. In a preferred embodiment, the fluid passage 3085 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 3015 is coupled to the innerstring adapter 3010 and the first inner sealing mandrel 3020. The sealing sleeve 3015 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 3015 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 3015 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The sealing sleeve 3015 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In a preferred embodiment, the sealing sleeve 3015 is removably coupled to the innerstring adapter 3010 by a standard threaded connection. The sealing sleeve 3015 may be coupled to the first inner sealing mandrel 3020 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the sealing sleeve 3015 is removably coupled to the first inner sealing mandrel 3020 by a standard threaded connection.

The sealing sleeve 3015 preferably includes a fluid passage 3090 that is adapted to convey fluidic materials from the fluid passage 3085 into the fluid passage 3095. In a preferred embodiment, the fluid passage 3090 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 is coupled to the sealing sleeve 3015, the hydraulic slips 3025, and the first lower sealing head 3035. The first inner sealing mandrel 3020 is further movably coupled to the first upper sealing head 3030. The first inner sealing mandrel 3020 preferably comprises a substantially hollow tubular member or members. The first inner sealing mandrel 3020 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or similar high strength materials. In a preferred embodiment, the first inner sealing mandrel 3020 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first inner sealing mandrel 3020 may be coupled to the sealing sleeve 3015 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 3020 is removably coupled to the sealing sleeve 3015 by a standard threaded connection. The first inner sealing mandrel 3020 may be coupled to the hydraulic slips 3025 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 3020 is removably coupled to the hydraulic slips 3025 by a standard threaded connection. The first inner sealing mandrel 3020 may be coupled to the first lower sealing head

3035 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first inner sealing mandrel 3020 is removably coupled to the first lower sealing head 3035 by a standard threaded connection.

The first inner sealing mandrel 3020 preferably includes a fluid passage 3095 that is adapted to convey fluidic materials from the fluid passage 3090 into the fluid passage 3100. In a preferred embodiment, the fluid passage 3095 is adapted to convey fluidic materials such as, for example, water, drilling mud, cement, epoxy, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 further preferably includes fluid passages 3110 that are adapted to convey fluidic materials from the fluid passage 3095 into the pressure chambers of the hydraulic slips 3025. In this manner, the slips 3025 are activated upon the pressurization of the fluid passage 3095 into contact with the inside surface of the casing 3075. In a preferred embodiment, the fluid passages 3110 are adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling fluids or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 further preferably includes fluid passages 3115 that are adapted to convey fluidic materials from the fluid passage 3095 into the first pressure chamber 3175 defined by the first upper sealing head 3030, the first lower sealing head 3035, the first inner sealing mandrel 3020, and the first outer sealing mandrel 3040. During operation of the apparatus 3000, pressurization of the pressure chamber 3175 causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 to move in an axial direction.

The slips 3025 are coupled to the outside surface of the first inner sealing mandrel 3020. During operation of the apparatus 3000, the slips 3025 are activated upon the pressurization of the fluid passage 3095 into contact with the inside surface of the casing 3075. In this manner, the slips 3025 maintain the casing 3075 in a substantially stationary position.

The slips 3025 preferably include fluid passages 3125, pressure chambers 3130, spring bias 3135, and slip members 3140. The slips 3025 may comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. In a preferred embodiment, the slips 3025 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 3075 during the expansion process.

The first upper sealing head 3030 is coupled to the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070. The first upper sealing head 3030 is also movably coupled to the outer surface of the first inner sealing mandrel 3020 and the inner surface of the casing 3075. In this manner, the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction.

The radial clearance between the inner cylindrical surface of the first upper sealing head 3030 and the outer surface of the first inner sealing mandrel 3020 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the first upper sealing head 3030 and the outer surface of the first inner sealing mandrel 3020 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the first upper sealing head 3030 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the

outer cylindrical surface of the first upper sealing head 3030 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process.

The first upper sealing head 3030 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first upper sealing head 3030 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or other similar high strength materials. In a preferred embodiment, the first upper sealing head 3030 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the first upper sealing head 3030 preferably includes one or more annular sealing members 3145 for sealing the interface between the first upper sealing head 3030 and the first inner sealing mandrel 3020. The sealing members 3145 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3145 comprise polypak seals available from Parker seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the first upper sealing head 3030 includes a shoulder 3150 for supporting the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 on the first lower sealing head 3035. The first upper sealing head 3030 may be coupled to the first outer sealing mandrel 3040 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the first upper sealing head 3030 is removably coupled to the first outer sealing mandrel 3040 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first upper sealing head 3030 and the first outer sealing

mandrel 3040 includes one or more sealing members 3155 for fluidicly sealing the interface between the first upper sealing head 3030 and the first outer sealing mandrel 3040. The sealing members 3155 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3155 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head 3035 is coupled to the first inner sealing mandrel 3020 and the second inner sealing mandrel 3045. The first lower sealing head 3035 is also movably coupled to the inner surface of the first outer sealing mandrel 3040. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the first lower sealing head 3035 and the inner surface of the first outer sealing mandrel 3040 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the first lower sealing head 3035 and the inner surface of the outer sealing mandrel 3040 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first lower sealing head 3035 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first lower sealing head 3035 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the first lower sealing head 3035 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the first lower sealing head 3035 preferably includes one or more annular sealing members 3160 for sealing the interface between the first lower sealing head 3035 and the first outer sealing mandrel 3040. The sealing

members 3160 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3160 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head 3035 may be coupled to the first inner sealing mandrel 3020 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first lower sealing head 3035 is removably coupled to the first inner sealing mandrel 3020 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first lower sealing head 3035 and the first inner sealing mandrel 3020 includes one or more sealing members 3165 for fluidicly sealing the interface between the first lower sealing head 3035 and the first inner sealing mandrel 3020. The sealing members 3165 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3165 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

The first lower sealing head 3035 may be coupled to the second inner sealing mandrel 3045 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first lower sealing head 3035 is removably coupled to the second inner sealing mandrel 3045 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first lower sealing head 3035 and the second inner sealing mandrel 3045 includes one or more sealing members 3170 for fluidicly sealing the interface between

the first lower sealing head 3035 and the second inner sealing mandrel 3045. The sealing members 3170 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3170 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel 3040 is coupled to the first upper sealing head 3030 and the second upper sealing head 3050. The first outer sealing mandrel 3040 is also movably coupled to the inner surface of the casing 3075 and the outer surface of the first lower sealing head 3035. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the first outer sealing mandrel 3040 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the first outer sealing mandrel 3040 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process. The radial clearance between the inner surface of the first outer sealing mandrel 3040 and the outer surface of the first lower sealing head 3035 may range, for example, from about 0.005 to 0.125 inches. In a preferred embodiment, the radial clearance between the inner surface of the first outer sealing mandrel 3040 and the outer surface of the first lower sealing head 3035 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first outer sealing mandrel 3040 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first outer sealing mandrel 3040 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a

preferred embodiment, the first outer sealing mandrel 3040 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first outer sealing mandrel 3040 may be coupled to the first upper sealing head 3030 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 3040 is removably coupled to the first upper sealing head 3030 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first outer sealing mandrel 3040 and the first upper sealing head 3030 includes one or more sealing members 3180 for sealing the interface between the first outer sealing mandrel 3040 and the first upper sealing head 3030. The sealing members 3180 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3180 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel 3040 may be coupled to the second upper sealing head 3050 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the first outer sealing mandrel 3040 is removably coupled to the second upper sealing head 3050 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the first outer sealing mandrel 3040 and the second upper sealing head 3050 includes one or more sealing members 3185 for sealing the interface between the first outer sealing mandrel 3040 and the second upper sealing head 3050. The sealing members 3185 may comprise any number of conventional commercially

available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3185 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second inner sealing mandrel 3045 is coupled to the first lower sealing head 3035 and the second lower sealing head 3055. The second inner sealing mandrel 3045 preferably comprises a substantially hollow tubular member or members. The second inner sealing mandrel 3045 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second inner sealing mandrel 3045 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second inner sealing mandrel 3045 may be coupled to the first lower sealing head 3035 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 3045 is removably coupled to the first lower sealing head 3035 by a standard threaded connection. The second inner sealing mandrel 3045 may be coupled to the second lower sealing head 3055 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection, or a standard threaded connection. In a preferred embodiment, the second inner sealing mandrel 3045 is removably coupled to the second lower sealing head 3055 by a standard threaded connection.

The second inner sealing mandrel 3045 preferably includes a fluid passage 3100 that is adapted to convey fluidic materials from the fluid passage 3095 into the fluid passage 3105. In a preferred embodiment, the fluid passage 3100 is adapted to

convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The second inner sealing mandrel 3045 further preferably includes fluid passages 3120 that are adapted to convey fluidic materials from the fluid passage 3100 into the second pressure chamber 3190 defined by the second upper sealing head 3050, the second lower sealing head 3055, the second inner sealing mandrel 3045, and the second outer sealing mandrel 3060. During operation of the apparatus 3000, pressurization of the second pressure chamber 3190 causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 to move in an axial direction.

The second upper sealing head 3050 is coupled to the first outer sealing mandrel 3040 and the second outer sealing mandrel 3060. The second upper sealing head 3050 is also movably coupled to the outer surface of the second inner sealing mandrel 3045 and the inner surface of the casing 3075. In this manner, the second upper sealing head 3050 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the second upper sealing head 3050 and the outer surface of the second inner sealing mandrel 3045 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the second upper sealing head 3050 and the outer surface of the second inner sealing mandrel 3045 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the second upper sealing head 3050 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the second upper sealing head 3050 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process.

The second upper sealing head 3050 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second upper sealing head 3050 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second upper sealing head 3050 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the second upper sealing head 3050 preferably includes one or more annular sealing members 3195 for sealing the interface between the second upper sealing head 3050 and the second inner sealing mandrel 3045. The sealing members 3195 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3195 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the second upper sealing head 3050 includes a shoulder 3200 for supporting the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 on the second lower sealing head 3055.

The second upper sealing head 3050 may be coupled to the first outer sealing mandrel 3040 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 3050 is removably coupled to the first outer sealing mandrel 3040 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second upper sealing head 3050 and the first outer sealing mandrel 3040 includes one or more sealing members 3185 for fluidicly sealing the interface between the second upper sealing head 3050 and the first outer sealing mandrel 3040. The second

upper sealing head 3050 may be coupled to the second outer sealing mandrel 3060 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the second upper sealing head 3050 is removably coupled to the second outer sealing mandrel 3060 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second upper sealing head 3050 and the second outer sealing mandrel 3060 includes one or more sealing members 3205 for fluidicly sealing the interface between the second upper sealing head 3050 and the second outer sealing mandrel 3060.

The second lower sealing head 3055 is coupled to the second inner sealing mandrel 3045 and the load mandrel 3065. The second lower sealing head 3055 is also movably coupled to the inner surface of the second outer sealing mandrel 3060. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing mandrel 3050, second outer sealing mandrel 3060, and expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 may range, for example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second lower sealing head 3055 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second lower sealing head 3055 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the second lower sealing head 3055 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction

surfaces. The outer surface of the second lower sealing head 3055 preferably includes one or more annular sealing members 3210 for sealing the interface between the second lower sealing head 3055 and the second outer sealing mandrel 3060. The sealing members 3210 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 3210 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 3055 may be coupled to the second inner sealing mandrel 3045 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 3055 is removably coupled to the second inner sealing mandrel 3045 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 3055 and the second inner sealing mandrel 3045 includes one or more sealing members 3215 for fluidicly sealing the interface between the second lower sealing head 3055 and the second inner sealing mandrel 3045. The sealing members 3215 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3215 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 3055 may be coupled to the load mandrel 3065 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second lower sealing head 3055 is removably coupled to the load mandrel 3065 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the second lower sealing head 3055 and the load mandrel 3065

includes one or more sealing members 3220 for fluidicly sealing the interface between the second lower sealing head 3055 and the load mandrel 3065. The sealing members 3220 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 3220 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the second lower sealing head 3055 includes a throat passage 3225 fluidicly coupled between the fluid passages 3100 and 3105. The throat passage 3225 is preferably of reduced size and is adapted to receive and engage with a plug 3230, or other similar device. In this manner, the fluid passage 3100 is fluidicly isolated from the fluid passage 3105. In this manner, the pressure chambers 3175 and 3190 are pressurized. Furthermore, the placement of the plug 3230 in the throat passage 3225 also pressurizes the pressure chambers 3130 of the hydraulic slips 3025.

The second outer sealing mandrel 3060 is coupled to the second upper sealing head 3050 and the expansion cone 3070. The second outer sealing mandrel 3060 is also movably coupled to the inner surface of the casing 3075 and the outer surface of the second lower sealing head 3055. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the second outer sealing mandrel 3060 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the second outer sealing mandrel 3060 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process. The radial clearance between the inner surface of the second outer sealing mandrel 3060 and the outer surface of the second lower sealing head 3055 may range, for example, from

about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner surface of the second outer sealing mandrel 3060 and the outer surface of the second lower sealing head 3055 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second outer sealing mandrel 3060 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second outer sealing mandrel 3060 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the second outer sealing mandrel 3060 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second outer sealing mandrel 3060 may be coupled to the second upper sealing head 3050 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 3060 is removably coupled to the second upper sealing head 3050 by a standard threaded connection. The second outer sealing mandrel 3060 may be coupled to the expansion cone 3070 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the second outer sealing mandrel 3060 is removably coupled to the expansion cone 3070 by a standard threaded connection.

The first upper sealing head 3030, the first lower sealing head 3035, the first inner sealing mandrel 3020, and the first outer sealing mandrel 3040 together define the first pressure chamber 3175. The second upper sealing head 3050, the second lower sealing head 3055, the second inner sealing mandrel 3045, and the second outer sealing mandrel 3060 together define the second pressure chamber 3190. The first

and second pressure chambers, 3175 and 3190, are fluidicly coupled to the passages, 3095 and 3100, via one or more passages, 3115 and 3120. During operation of the apparatus 3000, the plug 3230 engages with the throat passage 3225 to fluidicly isolate the fluid passage 3100 from the fluid passage 3105. The pressure chambers, 3175 and 3190, are then pressurized which in turn causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and expansion cone 3070 to reciprocate in the axial direction. The axial motion of the expansion cone 3070 in turn expands the casing 3075 in the radial direction. The use of a plurality of pressure chambers, 3175 and 3190, effectively multiplies the available driving force for the expansion cone 3070.

The load mandrel 3065 is coupled to the second lower sealing head 3055. The load mandrel 3065 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 3065 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 3065 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 3065 may be coupled to the lower sealing head 3055 using any number of conventional commercially available mechanical couplings such as, for example, epoxy, cement, water, drilling mud, or lubricants. In a preferred embodiment, the load mandrel 3065 is removably coupled to the lower sealing head 3055 by a standard threaded connection.

The load mandrel 3065 preferably includes a fluid passage 3105 that is adapted to convey fluidic materials from the fluid passage 3100 to the region outside of the apparatus 3000. In a preferred embodiment, the fluid passage 3105 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or

lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 3070 is coupled to the second outer sealing mandrel 3060. The expansion cone 3070 is also movably coupled to the inner surface of the casing 3075. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The reciprocation of the expansion cone 3070 causes the casing 3075 to expand in the radial direction.

The expansion cone 3070 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide an expansion cone 3070 for expanding typical casings. The axial length of the expansion cone 3070 may range, for example, from about 2 to 8 times the maximum outer diameter of the expansion cone 3070. In a preferred embodiment, the axial length of the expansion cone 3070 ranges from about 3 to 5 times the maximum outer diameter of the expansion cone 3070 in order to optimally provide stabilization and centralization of the expansion cone 3070 during the expansion process. In a particularly preferred embodiment, the maximum outside diameter of the expansion cone 3070 is between about 95 to 99 % of the inside diameter of the existing wellbore that the casing 3075 will be joined with. In a preferred embodiment, the angle of attack of the expansion cone 3070 ranges from about 5 to 30 degrees in order to optimally balance the frictional forces with the radial expansion forces.

The expansion cone 3070 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics, or other similar high strength materials. In a preferred embodiment, the expansion cone 3070 is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to wear and

galling. In a particularly preferred embodiment, the outside surface of the expansion cone 3070 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resistance to wear and galling.

The expansion cone 3070 may be coupled to the second outside sealing mandrel 3060 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In a preferred embodiment, the expansion cone 3070 is coupled to the second outside sealing mandrel 3060 using a standard threaded connection in order to optimally provide high strength and easy disassembly.

The casing 3075 is removably coupled to the slips 3025 and the expansion cone 3070. The casing 3075 preferably comprises a tubular member. The casing 3075 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, carbon steel, low alloy steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the casing 3075 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength.

In a preferred embodiment, the upper end 3235 of the casing 3075 includes a thin wall section 3240 and an outer annular sealing member 3245. In a preferred embodiment, the wall thickness of the thin wall section 3240 is about 50 to 100 % of the regular wall thickness of the casing 3075. In this manner, the upper end 3235 of the casing 3075 may be easily radially expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. In a preferred embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section 3240 of casing 3075 into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member 3245 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the annular sealing member 3245 is fabricated from StrataLock epoxy in order to optimally provide compressibility and wear resistance. The outside diameter of the annular sealing member 3245 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the wellbore casing that the casing 3075 is joined to. In this manner, after radial expansion, the annular sealing member 3245 optimally provides a fluidic seal and also preferably optimally provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing 3075 to support the casing 3075.

In a preferred embodiment, the lower end 3250 of the casing 3075 includes a thin wall section 3255 and an outer annular sealing member 3260. In a preferred embodiment, the wall thickness of the thin wall section 3255 is about 50 to 100 % of the regular wall thickness of the casing 3075. In this manner, the lower end 3250 of the casing 3075 may be easily expanded and deformed. Furthermore, in this manner, an other section of casing may be easily joined with the lower end 3250 of the casing 3075 using a radial expansion process. In a preferred embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section 3255 of the lower end 3250 of the casing 3075 results in a wellbore casing having a substantially constant inside diameter.

The upper annular sealing member 3245 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the upper annular sealing member 3245 is fabricated from Stratalock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the upper annular sealing member 3245 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 3075 is joined to.

In this manner, after radial expansion, the upper annular sealing member 3245 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 3075 to support the casing 3075.

The lower annular sealing member 3260 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the lower annular sealing member 3260 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the lower annular sealing member 3260 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 3075 is joined to. In this manner, the lower annular sealing member 3260 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 3075 to support the casing 3075.

During operation, the apparatus 3000 is preferably positioned in a wellbore with the upper end 3235 of the casing 3075 positioned in an overlapping relationship with the lower end of an existing wellbore casing. In a particularly preferred embodiment, the thin wall section 3240 of the casing 3075 is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing 3075 will compress the thin wall sections and annular compressible members of the upper end 3235 of the casing 3075 and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus 3000 in the wellbore, the casing 3000 is preferably supported by the expansion cone 3070.

After positioning the apparatus 3000, a first fluidic material is then pumped into the fluid passage 3080. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy, cement, slag mix or lubricants. In a preferred embodiment, the first

fluidic material comprises a hardenable fluidic sealing material such as, for example, cement, epoxy, or slag mix in order to optimally provide a hardenable outer annular body around the expanded casing 3075.

The first fluidic material may be pumped into the fluid passage 3080 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the fluid passage 3080 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operating efficiency.

The first fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100, and 3105 and then outside of the apparatus 3000. The first fluidic material then preferably fills the annular region between the outside of the apparatus 3000 and the interior walls of the wellbore.

The plug 3230 is then introduced into the fluid passage 3080. The plug 3230 lodges in the throat passage 3225 and fluidicly isolates and blocks off the fluid passage 3100. In a preferred embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 3080 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage 3080. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud, drilling gases, or lubricant in order to optimally provide pressurization of the pressure chambers 3175 and 3190.

The second fluidic material may be pumped into the fluid passage 3080 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic

material is pumped into the fluid passage 3080 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100 and into the pressure chambers 3130 of the slips 3025, and into the pressure chambers 3175 and 3190. Continued pumping of the second fluidic material pressurizes the pressure chambers 3130, 3175, and 3190.

The pressurization of the pressure chambers 3130 causes the hydraulic slip members 3140 to expand in the radial direction and grip the interior surface of the casing 3075. The casing 3075 is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chambers 3175 and 3190 cause the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 to move in an axial direction relative to the casing 3075. In this manner, the expansion cone 3070 will cause the casing 3075 to expand in the radial direction, beginning with the lower end 3250 of the casing 3075.

During the radial expansion process, the casing 3075 is prevented from moving in an upward direction by the slips 3025. A length of the casing 3075 is then expanded in the radial direction through the pressurization of the pressure chambers 3175 and 3190. The length of the casing 3075 that is expanded during the expansion process will be proportional to the stroke length of the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, and expansion cone 3070.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 drop to their rest positions with the casing 3075 supported by the expansion cone 3070. The reduction in the operating pressure of the second

fluidic material also causes the spring bias 3135 of the slips 3025 to pull the slip members 3140 away from the inside walls of the casing 3075.

The position of the drillpipe 3075 is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 3235. In a preferred embodiment, the stroking of the expansion cone 3070 is then repeated, as necessary, until the thin walled section 3240 of the upper end 3235 of the casing 3075 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

In a preferred embodiment, during the final stroke of the expansion cone 3070, the slips 3025 are positioned as close as possible to the thin walled section 3240 of the upper end 3235 of the casing 3075 in order minimize slippage between the casing 3075 and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the upper annular sealing member 3245 is selected to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing 3075 during the final stroke. Alternatively, or in addition, the outside diameter of the lower annular sealing member 3260 is selected to provide an interference fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further axial displacement of the casing 3075. In this final alternative, the interference fit is preferably selected to permit expansion of the casing 3075 by pulling the expansion cone 3070 out of the wellbore, without having to pressurize the pressure chambers 3175 and 3190.

During the radial expansion process, the pressurized areas of the apparatus 3000 are preferably limited to the fluid passages 3080, 3085, 3090, 3095, 3100, 3110,

3115, 3120, the pressure chambers 3130 within the slips 3025, and the pressure chambers 3175 and 3190. No fluid pressure acts directly on the casing 3075. This permits the use of operating pressures higher than the casing 3075 could normally withstand.

Once the casing 3075 has been completely expanded off of the expansion cone 3070, the remaining portions of the apparatus 3000 are removed from the wellbore. In a preferred embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end 3235 of the casing 3075 ranges from about 400 to 10,000 psi in order to optimally support the casing 3075 using the existing wellbore casing.

In this manner, the casing 3075 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 3080, 3085, 3090, 3095, 3100, 3110, 3115, and 3120, the pressure chambers 3130 of the slips 3025 and the pressure chambers 3175 and 3190 of the apparatus 3000.

In a preferred embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing 3075. In the case where the casing 3075 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 3075. The resulting new section of wellbore casing includes the expanded casing 3075 and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 3075 includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In a preferred embodiment, as the expansion cone 3070 nears the upper end 3235 of the casing 3075, the operating flow rate of the second fluidic material is

reduced in order to minimize shock to the apparatus 3000. In an alternative embodiment, the apparatus 3000 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 3075.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 3070 nears the end of the casing 3075 in order to optimally provide reduced axial movement and velocity of the expansion cone 3070. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 3000 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 3070 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 3000 ranges from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and also minimize the frequency at which the apparatus 3000 must be re-stroked.

In an alternative embodiment, at least a portion of one or both of the upper sealing heads, 3030 and 3050, includes an expansion cone for radially expanding the casing 3075 during operation of the apparatus 3000 in order to increase the surface area of the casing 3075 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Alternatively, the apparatus 3000 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 3000 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 3000 may be used to expand a tubular support member in a hole.

Referring now to Figure 21, an apparatus 3330 for isolating subterranean zones will be described. A wellbore 3305 including a casing 3310 are positioned in a subterranean formation 3315. The subterranean formation 3315 includes a number of productive and non-productive zones, including a water zone 3320 and a targeted oil sand zone 3325. During exploration of the subterranean formation 3315, the

wellbore 3305 may be extended in a well known manner to traverse the various productive and non-productive zones, including the water zone 3320 and the targeted oil sand zone 3325.

In a preferred embodiment, in order to fluidicly isolate the water zone 3320 from the targeted oil sand zone 3325, an apparatus 3330 is provided that includes one or more sections of solid casing 3335, one or more external seals 3340, one or more sections of slotted casing 3345, one or more intermediate sections of solid casing 3350, and a solid shoe 3355.

The solid casing 3335 may provide a fluid conduit that transmits fluids and other materials from one end of the solid casing 3335 to the other end of the solid casing 3335. The solid casing 3335 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. In a preferred embodiment, the solid casing 3335 comprises oilfield tubulars available from various foreign and domestic steel mills.

The solid casing 3335 is preferably coupled to the casing 3310. The solid casing 3335 may be coupled to the casing 3310 using any number of conventional commercially available processes such as, for example, welding, slotted and expandable connectors, or expandable solid connectors. In a preferred embodiment, the solid casing 3335 is coupled to the casing 3310 by using expandable solid connectors. The solid casing 3335 may comprise a plurality of such solid casings 3335.

The solid casing 3335 is preferably coupled to one more of the slotted casings 3345. The solid casing 3335 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or slotted and expandable connectors. In a preferred embodiment, the solid casing 3335 is coupled to the slotted casing 3345 by expandable solid connectors.

In a preferred embodiment, the casing 3335 includes one more valve members 3360 for controlling the flow of fluids and other materials within the interior region

of the casing 3335. In an alternative embodiment, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

In a particularly preferred embodiment, the casing 3335 is placed into the wellbore 3305 by expanding the casing 3335 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The casing 3335 may be expanded in the radial direction using any number of conventional commercially available methods. In a preferred embodiment, the casing 3335 is expanded in the radial direction using one or more of the processes and apparatus described within the present disclosure.

The seals 3340 prevent the passage of fluids and other materials within the annular region 3365 between the solid casings 3335 and 3350 and the wellbore 3305. The seals 3340 may comprise any number of conventional commercially available sealing materials suitable for sealing a casing in a wellbore such as, for example, lead, rubber or epoxy. In a preferred embodiment, the seals 3340 comprise Stratalok epoxy material available from Halliburton Energy Services.

The slotted casing 3345 permits fluids and other materials to pass into and out of the interior of the slotted casing 3345 from and to the annular region 3365. In this manner, oil and gas may be produced from a producing subterranean zone within a subterranean formation. The slotted casing 3345 may comprise any number of conventional commercially available sections of slotted tubular casing. In a preferred embodiment, the slotted casing 3345 comprises expandable slotted tubular casing available from Petroline in Abeerdeen, Scotland. In a particularly preferred embodiment, the slotted casing 145 comprises expandable slotted sandscreen tubular casing available from Petroline in Abeerdeen, Scotland.

The slotted casing 3345 is preferably coupled to one or more solid casing 3335. The slotted casing 3345 may be coupled to the solid casing 3335 using any number

of conventional commercially available processes such as, for example, welding, or slotted or solid expandable connectors. In a preferred embodiment, the slotted casing 3345 is coupled to the solid casing 3335 by expandable solid connectors.

The slotted casing 3345 is preferably coupled to one or more intermediate solid casings 3350. The slotted casing 3345 may be coupled to the intermediate solid casing 3350 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. In a preferred embodiment, the slotted casing 3345 is coupled to the intermediate solid casing 3350 by expandable solid connectors.

The last section of slotted casing 3345 is preferably coupled to the shoe 3355. The last slotted casing 3345 may be coupled to the shoe 3355 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. In a preferred embodiment, the last slotted casing 3345 is coupled to the shoe 3355 by an expandable solid connector.

In an alternative embodiment, the shoe 3355 is coupled directly to the last one of the intermediate solid casings 3350.

In a preferred embodiment, the slotted casings 3345 are positioned within the wellbore 3305 by expanding the slotted casings 3345 in a radial direction into intimate contact with the interior walls of the wellbore 3305. The slotted casings 3345 may be expanded in a radial direction using any number of conventional commercially available processes. In a preferred embodiment, the slotted casings 3345 are expanded in the radial direction using one or more of the processes and apparatus disclosed in the present disclosure with reference to Figures 14a-20.

The intermediate solid casing 3350 permits fluids and other materials to pass between adjacent slotted casings 3345. The intermediate solid casing 3350 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. In a preferred embodiment, the intermediate solid casing 3350 comprises oilfield tubulars available from foreign and domestic steel mills.

The intermediate solid casing 3350 is preferably coupled to one or more sections of the slotted casing 3345. The intermediate solid casing 3350 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or solid or slotted expandable connectors. In a preferred embodiment, the intermediate solid casing 3350 is coupled to the slotted casing 3345 by expandable solid connectors. The intermediate solid casing 3350 may comprise a plurality of such intermediate solid casing 3350.

In a preferred embodiment, each intermediate solid casing 3350 includes one more valve members 3370 for controlling the flow of fluids and other materials within the interior region of the intermediate casing 3350. In an alternative embodiment, as will be recognized by persons having ordinary skill in the art and the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

In a particularly preferred embodiment, the intermediate casing 3350 is placed into the wellbore 3305 by expanding the intermediate casing 3350 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The intermediate casing 3350 may be expanded in the radial direction using any number of conventional commercially available methods.

In an alternative embodiment, one or more of the intermediate solid casings 3350 may be omitted. In an alternative preferred embodiment, one or more of the slotted casings 3345 are provided with one or more seals 3340.

The shoe 3355 provides a support member for the apparatus 3330. In this manner, various production and exploration tools may be supported by the show 3350. The shoe 3350 may comprise any number of conventional commercially available shoes suitable for use in a wellbore such as, for example, cement filled shoe, or an aluminum or composite shoe. In a preferred embodiment, the shoe 3350

comprises an aluminum shoe available from Halliburton. In a preferred embodiment, the shoe 3355 is selected to provide sufficient strength in compression and tension to permit the use of high capacity production and exploration tools.

In a particularly preferred embodiment, the apparatus 3330 includes a plurality of solid casings 3335, a plurality of seals 3340, a plurality of slotted casings 3345, a plurality of intermediate solid casings 3350, and a shoe 3355. More generally, the apparatus 3330 may comprise one or more solid casings 3335, each with one or more valve members 3360, n slotted casings 3345, n-1 intermediate solid casings 3350, each with one or more valve members 3370, and a shoe 3355.

During operation of the apparatus 3330, oil and gas may be controllably produced from the targeted oil sand zone 3325 using the slotted casings 3345. The oil and gas may then be transported to a surface location using the solid casing 3335. The use of intermediate solid casings 3350 with valve members 3370 permits isolated sections of the zone 3325 to be selectively isolated for production. The seals 3340 permit the zone 3325 to be fluidicly isolated from the zone 3320. The seals 3340 further permits isolated sections of the zone 3325 to be fluidicly isolated from each other. In this manner, the apparatus 3330 permits unwanted and/or non-productive subterranean zones to be fluidicly isolated.

In an alternative embodiment, as will be recognized by persons having ordinary skill in the art and also having the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

Referring to Figures 22a, 22b, 22c and 22d, an embodiment of an apparatus 3500 for forming a wellbore casing while drilling a wellbore will now be described. In a preferred embodiment, the apparatus 3500 includes a support member 3505, a mandrel 3510, a mandrel launcher 3515, a shoe 3520, a tubular member 3525, a mud

motor 3530, a drill bit 3535, a first fluid passage 3540, a second fluid passage 3545, a pressure chamber 3550, a third fluid passage 3555, a cup seal 3560, a body of lubricant 3565, seals 3570, and a releasable coupling 3600.

The support member 3505 is coupled to the mandrel 3510. The support member 3505 preferably comprises an annular member having sufficient strength to carry and support the apparatus 3500 within the wellbore 3575. In a preferred embodiment, the support member 3505 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 3500.

The support member 3505 may comprise one or more sections of conventional commercially available tubular materials such as, for example, oilfield country tubular goods, low alloy steel, stainless steel or carbon steel. In a preferred embodiment, the support member 3505 comprises coiled tubing or drillpipe in order to optimally permit the placement of the apparatus 3500 within a non-vertical wellbore.

In a preferred embodiment, the support member 3505 includes a first fluid passage 3540 for conveying fluidic materials from a surface location to the fluid passage 3545. In a preferred embodiment, the first fluid passage 3540 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix at operating pressures and flow rates ranging from about 0 to 10,000 psi and 0 to 3,000 gallons/minute.

The mandrel 3510 is coupled to and supported by the support member 3505. The mandrel 3510 is also coupled to and supports the mandrel launcher 3515 and tubular member 3525. The mandrel 3510 is preferably adapted to controllably expand in a radial direction. The mandrel 3510 may comprise any number of conventional commercially available mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the mandrel 3510 comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

In a preferred embodiment, the mandrel 3510 includes one or more conical sections for expanding the tubular member 3525 in the radial direction. In a preferred embodiment, the outer surfaces of the conical sections of the mandrel 3510 have a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally radially expand the tubular member 3525.

In a preferred embodiment, the mandrel 3510 includes a second fluid passage 3545 fluidicly coupled to the first fluid passage 3540 and the pressure chamber 3550 for conveying fluidic materials from the first fluid passage 3540 to the pressure chamber 3550. In a preferred embodiment, the second fluid passage 3545 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 3,500 gallons/minute in order to optimally provide operating pressure for efficient operation.

The mandrel launcher 3515 is coupled to the tubular member 3525, the mandrel 3510, and the shoe 3520. The mandrel launcher 3515 preferably comprises a tapered annular member that mates with at a portion of at least one of the conical portions of the outer surface of the mandrel 3510. In a preferred embodiment, the wall thickness of the mandrel launcher is less than the wall thickness of the tubular member 3525 in order to facilitate the initiation of the radial expansion process and facilitate the placement of the apparatus in openings having tight clearances. In a preferred embodiment, the wall thickness of the mandrel launcher 3515 ranges from about 50 to 100 % of the wall thickness of the tubular member 3525 immediately adjacent to the mandrel launcher 3515 in order to optimally faciliate the radial expansion process and facilitate the insertion of the apparatus 3500 into wellbore casings and other areas with tight clearances.

The mandrel launcher 3515 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel or stainless steel. In a preferred embodiment, the mandrel launcher 3515 is fabricated from oilfield country tubular

goods of higher strength by lower wall thickness than the tubular member 3525 in order to optimally provide a smaller container having approximately the same burst strength as the tubular member 3525.

The shoe 3520 is coupled to the mandrel launcher 3515 and the releasable coupling 3600. The shoe 3520 preferably comprises a substantially annular member. In a preferred embodiment, the shoe 3520 or the releasable coupling 3600 include a third fluid passage 3555 fluidicly coupled to the pressure chamber 3550 and the mud motor 3530.

The shoe 3520 may comprise any number of conventional commercially available shoes such as, for example, cement filled, aluminum or composite modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 3520 comprises a high strength shoe having a burst strength approximately equal to the burst strength of the tubular member 3525 and mandrel launcher 3515. The shoe 3520 is preferably coupled to the mud motor 3520 by a releasable coupling 3600 in order to optimally provide for removal of the mud motor 3530 and drill nit 3535 upon the completion of a drilling and casing operation.

In a preferred embodiment, the shoe 3520 includes a releasable latch mechanism 3600 for retrieving and removing the mud motor 3530 and drill bit 3535 upon the completion of the drilling and casing formation operations. In a preferred embodiment, the shoe 3520 further includes an anti-rotation device for maintaining the shoe 3520 in a substantially stationary rotational position during operation of the apparatus 3500. In a preferred embodiment, the releasable latch mechanism 3600 is releasably coupled to the shoe 3520.

The tubular member 3525 is supported by and coupled to the mandrel 3510. The tubular member 3525 is expanded in the radial direction and extruded off of the mandrel 3510. The tubular member 3525 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, automotive grade steel, or plastic tubing/casing. In a preferred embodiment, the tubular member 3525 is

fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 3525 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the inner and outer diameters of the tubular member 3525 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 3525 preferably comprises an annular member with solid walls.

In a preferred embodiment, the upper end portion 3580 of the tubular member 3525 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 3510 when the mandrel 3510 completes the extrusion of tubular member 3525. For typical tubular member 3525 materials, the length of the tubular member 3525 is preferably limited to between about 40 to 20,000 feet in length. The tubular member 3525 may comprise a single tubular member or, alternatively, a plurality of tubular members coupled to one another.

The mud motor 3530 is coupled to the shoe 3520 and the drill bit 3535. The mud motor 3530 is also fluidicly coupled to the fluid passage 3555. In a preferred embodiment, the mud motor 3530 is driven by fluidic materials such as, for example, drilling mud, water, cement, epoxy, lubricants or slag mix conveyed from the fluid passage 3555 to the mud motor 3530. In this manner, the mud motor 3530 drives the drill bit 3535. The operating pressures and flow rates for operating mud motor 3530 may range, for example, from about 0 to 12,000 psi and 0 to 10,000 gallons/minute. In a preferred embodiment, the operating pressures and flow rates for operating mud motor 3530 range from about 0 to 5,000 psi and 40 to 3,000 gallons/minute.

The mud motor 3530 may comprise any number of conventional commercially available mud motors, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may

be retrieved from the downhole location upon the conclusion of the drilling and casing operations.

The drill bit 3535 is coupled to the mud motor 3530. The drill bit 3535 is preferably adapted to be powered by the mud motor 3530. In this manner, the drill bit 3535 drills out new sections of the wellbore 3575.

The drill bit 3535 may comprise any number of conventional commercially available drill bits, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may be retrieved from the downhole location upon the conclusion of the drilling and casing operations. In several alternative preferred embodiments, the drill bit 3535 comprises an eccentric drill bit, a bi-centered drill bit, or a small diameter drill bit with an hydraulically actuated under reamer.

The first fluid passage 3540 permits fluidic materials to be transported to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage 3555, and the mud motor 3530. The first fluid passage 3540 is coupled to and positioned within the support member 3505. The first fluid passage 3540 preferably extends from a position adjacent to the surface to the second fluid passage 3545 within the mandrel 3510. The first fluid passage 3540 is preferably positioned along a centerline of the apparatus 3500.

The second fluid passage 3545 permits fluidic materials to be conveyed from the first fluid passage 3540 to the pressure chamber 3550, the third fluid passage 3555, and the mud motor 3530. The second fluid passage 3545 is coupled to and positioned within the mandrel 3510. The second fluid passage 3545 preferably extends from a position adjacent to the first fluid passage 3540 to the bottom of the mandrel 3510. The second fluid passage 3545 is preferably positioned substantially along the centerline of the apparatus 3500.

The pressure chamber 3550 permits fluidic materials to be conveyed from the second fluid passage 3545 to the third fluid passage 3555, and the mud motor 3530. The pressure chamber is preferably defined by the region below the mandrel 3510 and within the tubular member 3525, mandrel launcher 3515, shoe 3520, and releasable coupling 3600. During operation of the apparatus 3500, pressurization of the pressure chamber 3550 preferably causes the tubular member 3525 to be extruded off of the mandrel 3510.

The third fluid passage 3555 permits fluidic materials to be conveyed from the pressure chamber 3550 to the mud motor 3530. The third fluid passage 3555 may be coupled to and positioned within the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 preferably extends from a position adjacent to the pressure chamber 3550 to the bottom of the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 is preferably positioned substantially along the centerline of the apparatus 3500.

The fluid passages 3540, 3545, and 3555 are preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally operational efficiency.

The cup seal 3560 is coupled to and supported by the outer surface of the support member 3505. The cup seal 3560 prevents foreign materials from entering the interior region of the tubular member 3525. The cup seal 3560 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the cup seal 3560 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant. In a preferred embodiment, the apparatus 3500 includes a plurality of such cup seals in order to optimally prevent the entry of foreign material into the interior region of the tubular member 3525 in the vicinity of the mandrel 3510.

In a preferred embodiment, a quantity of lubricant 3565 is provided in the annular region above the mandrel 3510 within the interior of the tubular member 3525. In this manner, the extrusion of the tubular member 3525 off of the mandrel 3510 is facilitated. The lubricant 3565 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 3565 comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to faciliate the expansion process.

The seals 3570 are coupled to and supported by the end portion 3580 of the tubular member 3525. The seals 3570 are further positioned on an outer surface of the end portion 3580 of the tubular member 3525. The seals 3570 permit the overlapping joint between the lower end portion 3585 of a preexisting section of casing 3590 and the end portion 3580 of the tubular member 3525 to be fluidicly sealed. The seals 3570 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 3570 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 3580 of the tubular member 3525 and the end 3585 of the pre-existing casing 3590.

In a preferred embodiment, the seals 3570 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 3525 from the pre-existing casing 3590. In a preferred embodiment, the frictional force optimally provided by the seals 3570 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 3525.

The releasable coupling 3600 is preferably releasably coupled to the bottom of the shoe 3520. In a preferred embodiment, the releasable coupling 3600 includes fluidic seals for sealing the interface between the releasable coupling 3600 and the

shoe 3520. In this manner, the pressure chamber 3550 may be pressurized. The releasable coupling 3600 may comprise any number of conventional commercially available releasable couplings suitable for drilling operations modified in accordance with the teachings of the present disclosure.

As illustrated in Figure 22A, during operation of the apparatus 3500, the apparatus 3500 is preferably initially positioned within a preexisting section of a wellbore 3575 including a preexisting section of wellbore casing 3590. In a preferred embodiment, the upper end portion 3580 of the tubular member 3525 is positioned in an overlapping relationship with the lower end 3585 of the preexisting section of casing 3590. In a preferred embodiment, the apparatus 3500 is initially positioned in the wellbore 3575 with the drill bit 353 in contact with the bottom of the wellbore 3575. During the initial placement of the apparatus 3500 in the wellbore 3575, the tubular member 3525 is preferably supported by the mandrel 3510.

As illustrated in Figure 22B, a fluidic material 3595 is then pumped into the first fluid passage 3540. The fluidic material 3595 is preferably conveyed from the first fluid passage 3540 to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage 3555 and the inlet to the mud motor 3530. The fluidic material 3595 may comprise any number of conventional commercially available fluidic materials such as, for example, drilling mud, water, cement, epoxy or slag mix. The fluidic material 3595 may be pumped into the first fluid passage 3540 at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The fluidic material 3595 will enter the inlet for the mud motor 3530 and drive the mud motor 3530. The fluidic material 3595 will then exit the mud motor 3530 and enter the annular region surrounding the apparatus 3500 within the wellbore 3575. The mud motor 3530 will in turn drive the drill bit 3535. The operation of the drill bit 3535 will drill out a new section of the wellbore 3575.

In the case where the fluidic material 3595 comprises a hardenable fluidic material, the fluidic material 3595 preferably is permitted to cure and form an outer

annular body surrounding the periphery of the expanded tubular member 3525. Alternatively, in the case where the fluidic material 3595 is a non-hardenable fluidic material, the tubular member 3595 preferably is expanded into intimate contact with the interior walls of the wellbore 3575. In this manner, an outer annular body is not provided in all applications.

As illustrated in Figure 22C, at some point during operation of the mud motor 3530 and drill bit 3535, the pressure drop across the mud motor 3530 will create sufficient back pressure to cause the operating pressure within the pressure chamber 3550 to elevate to the pressure necessary to extrude the tubular member 3525 off of the mandrel 3510. The elevation of the operating pressure within the pressure chamber 3550 will then cause the tubular member 3525 to extrude off of the mandrel 3510 as illustrated in Figure 22D. For typical tubular members 3525, the necessary operating pressure may range, for example, from about 1,000 to 9,000 psi. In this manner, a wellbore casing is formed simultaneous with the drilling out of a new section of wellbore.

In a particularly preferred embodiment, during the operation of the apparatus 3500, the apparatus 3500 is lowered into the wellbore 3575 until the drill bit 3535 is proximate the bottom of the wellbore 3575. Throughout this process, the tubular member 3525 is preferably supported by the mandrel 3510. The apparatus 3500 is then lowered until the drill bit 3535 is placed in contact with the bottom of the wellbore 3575. At this point, at least a portion of the weight of the tubular member 3525 is supported by the drill bit 3535.

The fluidic material 3595 is then pumped into the first fluid passage 3540, second fluid passage 3545, pressure chamber 3550, third fluid passage 3555, and the inlet of the mud motor 3530. The mud motor 3530 then drives the drill bit 3535 to drill out a new section of the wellbore 3575. Once the differential pressure across the mud motor 3530 exceeds the minimum extrusion pressure for the tubular member 3525, the tubular member 3525 begins to extrude off of the mandrel 3510. As the tubular member 3525 is extruded off of the mandrel 3510, the weight of the extruded

portion of the tubular member 3525 is transferred to and supported by the drill bit 3535. In a preferred embodiment, the pumping pressure of the fluidic material 3595 is maintained substantially constant throughout this process. At some point during the process of extruding the tubular member 3525 off of the mandrel 3510, a sufficient portion of the weight of the tubular member 3525 is transferred to the drill bit 3535 to stop the extrusion process due to the opposing force. Continued drilling by the drill bit 3535 eventually transfers a sufficient portion of the weight of the extruded portion of the tubular member 3525 back to the mandrel 3510. At this point, the extrusion of the tubular member 3525 off of the mandrel 3510 continues. In this manner, the support member 3505 never has to be moved and no drillpipe connections have to be made at the surface since the new section of the wellbore casing within the newly drilled section of wellbore is created by the constant downward feeding of the expanded tubular member 3525 off of the mandrel 3510.

Once the new section of wellbore that is lined with the fully expanded tubular member 3525 is completed, the support member 3505 and mandrel 3510 are removed from the wellbore 3575. The drilling assembly including the mud motor 3530 and drill bit 3535 are then preferably removed by lowering a drillstring into the new section of wellbore casing and retrieving the drilling assembly by using the latch 3600. The expanded tubular member 3525 is then cemented using conventional squeeze cementing methods to provide a solid annular sealing member around the periphery of the expanded tubular member 3525.

Alternatively, the apparatus 3500 may be used to repair or form an underground pipeline or form a support member for a structure. In several preferred alternative embodiments, the teachings of the apparatus 3500 are combined with the teachings of the embodiments illustrated in Figures 1-21. For example, by operably coupling the mud motor 3530 and drill bit 3535 to the pressure chambers used to cause the radial expansion of the tubular members of the embodiments illustrated and described with reference to Figures 1-21, the use of plugs may be eliminated and

radial expansion of tubular members can be combined with the drilling out of new sections of wellbore.

Referring now to FIGS. 23A, 23B and 23C, an apparatus 3700 for expanding a tubular member will be described. In a preferred embodiment, the apparatus 3700 includes a support member 3705, a packer 3710, a first fluid conduit 3715, an annular fluid passage 3720, fluid inlets 3725, an annular seal 3730, a second fluid conduit 3735, a fluid passage 3740, a mandrel 3745, a mandrel launcher 3750, a tubular member 3755, slips 3760, and seals 3765. In a preferred embodiment, the apparatus 3700 is used to radially expand the tubular member 3755. In this manner, the apparatus 3700 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural support member. In a preferred embodiment, the apparatus 3700 is used to clad at least a portion of the tubular member 3755 onto a preexisting tubular member.

The support member 3705 is preferably coupled to the packer 3710 and the mandrel launcher 3750. The support member 3705 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 3705 is preferably selected to fit through a preexisting section of wellbore casing 3770. In this manner, the apparatus 3700 may be positioned within the wellbore casing 3770. In a preferred embodiment, the support member 3705 is releasably coupled to the mandrel launcher 3750. In this manner, the support member 3705 may be decoupled from the mandrel launcher 3750 upon the completion of an extrusion operation.

The packer 3710 is coupled to the support member 3705 and the first fluid conduit 3715. The packer 3710 preferably provides a fluid seal between the outside surface of the first fluid conduit 3715 and the inside surface of the support member 3705. In this manner, the packer 3710 preferably seals off and, in combination with the support member 3705, first fluid conduit 3715, second fluid conduit 3735, and

mandrel 3745, defines an annular chamber 3775. The packer 3710 may comprise any number of conventional commercially available packers modified in accordance with the teachings of the present disclosure.

The first fluid conduit 3715 is coupled to the packer 3710 and the annular seal 3730. The first fluid conduit 3715 preferably comprises an annular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. In a preferred embodiment, the first fluid conduit 3715 includes one or more fluid inlets 3725 for conveying fluidic materials from the annular fluid passage 3720 into the chamber 3775.

The annular fluid passage 3720 is defined by and positioned between the interior surface of the first fluid conduit 3715 and the interior surface of the second fluid conduit 3735. The annular fluid passage 3720 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid inlets 3725 are positioned in an end portion of the first fluid conduit 3715. The fluid inlets 3725 preferably are adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The annular seal 3730 is coupled to the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735 during relative axial motion of the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 may comprise any number of conventional commercially available seals such as, for example, o-rings,

polypak seals or metal spring energized seals. In a preferred embodiment, the annular seal 3730 comprises a polypak seal available from Parker Seals in order to optimally provide sealing for axial motion.

The second fluid conduit 3735 is coupled to the annular seal 3730 and the mandrel 3745. The second fluid conduit preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, coiled tubing, oilfield country tubular goods, low alloy steel, stainless steel, or low carbon steel. In a preferred embodiment, the second fluid conduit 3735 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid passage 3740 is coupled to the second fluid conduit 3735 and the mandrel 3745. In a preferred embodiment, the fluid passage 3740 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The mandrel 3745 is coupled to the second fluid conduit 3735 and the mandrel launcher 3750. The mandrel 3745 preferably comprise an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, carbon steel, tool steel, ceramics, or composite materials. In a preferred embodiment, the angle of attack the conic section of the mandrel 3745 ranges from about 10 to 30 degrees in order to optimally expand the mandrel launcher 3750 and tubular member 3755 in the radial direction. In a preferred embodiment, the surface hardness of the conic section of the mandrel 3745 ranges from about 50 Rockwell C to 70 Rockwell C. In a particularly preferred embodiment, the surface hardness of the outer surface of the conic section of the mandrel 3745 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In an alternative embodiment, the mandrel

radial expansion process is typically extremely small, and the operating contact pressures between the tubular member 5005 and the expansion mandrel 5000 are extremely high, the quantity of lubricating fluid provided to the trailing edge portion 5030 is typically greatly reduced. In typical radial expansion operations, this reduction in lubrication in the trailing edge portion 5030 increases the forces required to radially expand the tubular member 5005.

Referring to FIG. 32, an embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 32, an expansion cone 5100, having a front end 5100a and a rear end 5100b, includes a tapered portion 5105 having an outer surface 3110, one or more circumferential grooves 5115a and 5115b, and one more internal flow passages 5120a and 5120b.

In a preferred embodiment, the circumferential grooves 5115 are fluidicly coupled to the internal flow passages 5120. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5100a of the expansion cone 5100 into the circumferential grooves 5115. Thus, the trailing edge portion of the interface between the expansion cone 5100 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In a preferred embodiment, the lubricating fluids are injected into the internal flow passages 5120 using a fluid conduit that is coupled to the tapered end 5105 of the expansion cone 5100. Alternatively, lubricating fluids are provided for the internal flow passages 5120 using a supply of lubricating fluids provided adjacent to the front 5100a of the expansion cone 5100.

In a preferred embodiment, the expansion cone 5100 includes a plurality of circumferential grooves 5115. In a preferred embodiment, the cross sectional area of the circumferential grooves 5115 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5100 includes circumferential grooves 5115 concentrated about the axial midpoint of the tapered portion 5105 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5115 are equally spaced along the trailing edge portion of the expansion cone 5100 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5100 includes a plurality of flow passages 5120 coupled to each of the circumferential grooves 5115. In a preferred embodiment, the cross-sectional area of the flow passages 5120 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5115 is greater than the cross sectional area of the flow passage 5120 in order to minimize resistance to fluid flow.

Referring to FIG. 33, another embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 33, an expansion cone 5200, having a front end 5200a and a rear end 5200b, includes a tapered portion 5205 having an outer surface 5210, one or more circumferential grooves 5215a and 5215b, and one or more axial grooves 5220a and 5220b.

In a preferred embodiment, the circumferential grooves 5215 are fluidicly coupled to the axial groves 5220. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5200a of the expansion cone 5200 into the circumferential grooves 5215. Thus, the trailing edge portion of the interface between the expansion cone 5200 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. In a preferred embodiment,

the axial grooves 5220 are provided with lubricating fluid using a supply of lubricating fluid positioned proximate the front end 5200a of the expansion cone 5200. In a preferred embodiment, the circumferential grooves 3215 are concentrated about the axial midpoint of the tapered portion 5205 of the expansion cone 5200 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5215 are equally spaced along the trailing edge portion of the expansion cone 5200 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5200 includes a plurality of circumferential grooves 5215. In a preferred embodiment, the cross sectional area of the circumferential grooves 5215 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5200 includes a plurality of axial grooves 5220 coupled to each of the circumferential grooves 5215. In a preferred embodiment, the cross sectional area of the axial grooves 5220 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5215 is greater than the cross sectional area of the axial grooves 5220 in order to minimize resistance to fluid flow. In a preferred embodiment, the axial groves 5220 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 34, another embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 34, an expansion cone 5300,

having a front end 5300a and a rear end 5300b, includes a tapered portion 5305 having an outer surface 5310, one or more circumferential grooves 5315a and 5315b, and one or more internal flow passages 5320a and 5320b.

In a preferred embodiment, the circumferential grooves 5315 are fluidicly coupled to the internal flow passages 5320. In this manner, during the radial expansion process, lubricating fluids are transmitted from the areas in front of the front 5300a and/or behind the rear 5300b of the expansion cone 5300 into the circumferential grooves 5315. Thus, the trailing edge portion of the interface between the expansion cone 5300 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. Furthermore, the lubricating fluids also preferably pass to the area in front of the expansion cone. In this manner, the area adjacent to the front 5300a of the expansion cone 5300 is cleaned of foreign materials. In a preferred embodiment, the lubricating fluids are injected into the internal flow passages 5320 by pressurizing the area behind the rear 5300b of the expansion cone 5300 during the radial expansion process.

In a preferred embodiment, the expansion cone 5300 includes a plurality of circumferential grooves 5315. In a preferred embodiment, the cross sectional area of the circumferential grooves 5315 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 respectively, in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. In a preferred embodiment, the expansion cone 5300 includes circumferential grooves 5315 that are concentrated about the axial midpoint of the tapered portion 5305 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. In a preferred embodiment, the circumferential grooves 5315 are equally spaced along the trailing edge portion of the expansion cone 5300 in order to optimally provide lubrication to the trailing edge portion of the

interface between the expansion cone 5300 and a tubular member during the radial expansion process.

In a preferred embodiment, the expansion cone 5300 includes a plurality of flow passages 5320 coupled to each of the circumferential grooves 5315. In a preferred embodiment, the flow passages 5320 fluidicly couple the front end 5300a and the rear end 5300b of the expansion cone 5300. In a preferred embodiment, the cross-sectional area of the flow passages 5320 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. In a preferred embodiment, the cross sectional area of the circumferential grooves 5315 is greater than the cross-sectional area of the flow passages 5320 in order to minimize resistance to fluid flow.

Referring to FIG. 35, an embodiment of a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 35, an expansion cone 5400, having a front end 5400a and a rear end 5400b, includes a tapered portion 5405 having an outer surface 5410, one or more circumferential grooves 5415a and 5415b, and one or more axial grooves 5420a and 5420b.

In a preferred embodiment, the circumferential grooves 5415 are fluidicly coupled to the axial grooves 5420. In this manner, during the radial expansion process, lubricating fluids are transmitted from the areas in front of the front 5400a and/or behind the rear 5400b of the expansion cone 5400 into the circumferential grooves 5415. Thus, the trailing edge portion of the interface between the expansion cone 5400 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. Furthermore, in a preferred embodiment, pressurized lubricating fluids pass from the fluid passages 5420 to the area in front of the front 5400a of the expansion cone 5400. In this manner, the area adjacent to the front 5400a of the expansion cone 5400 is cleaned of foreign materials. In a preferred embodiment, the

ranges from about 10 to 30 degrees in order to minimize the range of required minimum propagation pressure P_{PR}.

Referring to FIG. 27, an embodiment of an expandable threaded connection 4300 will now be described. The expandable threaded connection 4300 preferably includes a first tubular member 4305, a second tubular member 4310, a threaded connection 4315, an O-ring groove 4320, and an O-ring 4325.

The first tubular member 4305 includes an inside wall 4330 and an outside wall 4335. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4310 includes an inside wall 4340 and an outside wall 4345. The second tubular member 4310 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4305 and 4310, may comprise any number of conventional commercially available members. In a preferred embodiment, the inside and outside diameters of the first and second tubular members, 4305 and 4310, are substantially equal. In this manner, the burst strength of the tubular members, 4305 and 4310, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4315 may comprise any number of conventional threaded connections suitable for use with tubular members. In a preferred embodiment, the threaded connection 4315 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4305 to the second tubular member 4310 is optimized.

The O-ring groove 4320 is preferably provided in the threaded portion of the interior wall 4340 of the second tubular member 4310. The O-ring groove 4320 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4320 is preferably selected to permit the O-ring 4325 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4345 of the second tubular member